PETROLEUM CONSERVATION

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PETROLEUM CONSERVATION

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Buckley, Stuart E ed.

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PETROLEUM CONSERVATION

Edited by

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PREFACE

The fundamental concept governing modern practice in the production of oil is that all recoverable oil in its undisturbed reservoir state contains gas in solution; that such solution has lower viscosity, lower specific gravity and lower surface tension than gas-free oil; and that the expansion of the dissolved gas is in many fields the single important agent and in most fields a potent agent which moves the solution to the well.

The petroleum industry owes a deep scientific debt to Mr. Henry L. Doherty. Mr. Doherty was a self-educated, clear-thinking and far-sighted technician. He thoroughly enjoyed the challenge which he sensed in his theory of petroleum reservoir characteristics. If his theory could be proved as he visualized it, he believed such proof would result in a tremendously important contribution to the conservation of petroleum resources. With that background and incentive, he applied himself to an intensive consideration of the nature of occurrence of oil and, once the solution of the problem appeared to be within his grasp, he directed his technical men in making basic scientific tests which should prove or disprove his theory. The research into the physical nature of the oil-gas solution, conducted under Mr. Doherty's direction, resulted in the classic paper by Beecher and Parkhurst on "Effect of Dissolved Gases upon the Viscosity and Surface Tension of Crude Oil." This notable paper, presented before this Institute in 1926, placed the gas concept upon a firmer foundation than it had ever previously had and brought the whole matter of its application nearer to a quantitative base.

The industry readily accepted Mr. Doherty's concept of gas as reservoir energy and recognized the need for effectively utilizing this energy in the production of oil. The principle of optimum or maximum efficient rate of production is the direct evolution of Mr. Doherty's early work in gas conservation. With his realization of the fact that each individual oil pool is a mechanical unit and should be operated as such regardless of divisions of ownership, he became the great protagonist of unit operation.

The industry did not at first accept this bold championship of unit operation with a hospitable mind. Mr. Doherty was a director of the American Petroleum Institute but at its 1924 meeting in

11/3/52 Petroleum Branch Geology

Fort Worth his fellow directors refused either to allow him to make a public presentation of his views from their platform or, at that time, to accord him a hearing. A special meeting of the directors was held in Atlantic City in January 1925 to hear him, and his views were coldly received.

It must always be a matter for pride that the Petroleum Division of the American Institute of Mining and Metallurgical Engineers invited Mr. Doherty to use its forum and that the first public and adequate presentation of his ideas was made by him at its New York meeting, February 1925. The gas concept was not discovered by Mr. Doherty. Rather he rediscovered it but, more than anything else, he made it his own by his vigorous championship of unit operation.

A certain Mr. Briggs first proposed the familiar soda water analogy to explain the production of oil, before the American Philosophical Society in 1865. John F. Carrl, expert to the Second Pennsylvania Geological Survey, presented it again, using a barrel of beer as a homely and understandable example, in a report of that survey, 1880. These early essays were almost forgotten for many years and it was not until 1913 that the gas concept was clearly restated. This was in a paper by L. G. Huntley published by the U. S. Bureau of Mines. J. O. Lewis, then petroleum engineer in the Bureau—and a few years later its chief petroleum technologist—failed to recognize the energy function of gas in 1916 but stated it clearly the following year. He also clearly foreshadowed the importance of low gas-oil ratios in oil production.

Although the American Petroleum Institute may not have accorded Mr. Doherty's ideas a friendly reception upon their first presentation, it soon reversed its attitude. A committee known as the Gas Conservation Committee was appointed under the chairmanship of E. W. Marland which met in September 1927. A technical subcommittee was formed and reported back in Ponca City on October 17. The material so collected was restudied and a report on "The Function of Natural Gas in the Production of Oil," by H. C. Miller, was prepared by the U. S. Bureau of Mines in cooperation with the American Petroleum Institute and was published by the Institute in 1929.

Mr. Doherty was not a man for half measures. He proposed compulsory unitization in order to make possible the orderly and efficient exploitation of oil fields. It was probably the compulsory phase of his proposal which the industry feared. No one can read this volume attentively, however, without realizing how extremely fruitful have been Mr. Doherty's pioneer promotions of unit operation and how exceedingly great have been the contributions they have made to modern oil-field practice and conservation.

HENRY L. DOHERTY
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INTRODUCTION

As the production of petroleum in the United States increases year after year, repeatedly breaking old records and rising to new heights, it is becoming increasingly apparent to those who study the source of the supply that the tremendous production of both oil and natural gas in this country is not the result of chance, is not the result of boundless native resources, but is, instead, a direct reflection of scientific and technologic developments and improvements in the search for and resultant discovery of oil and gas, and in the process of recovery. But for the technologic improvements that have taken place in both exploration and production the available supply of oil and gas within the United States would long since have dwindled to insignificance.

The application of science, engineering, and ingenuity, and the organization of these through effective management into an efficient and competent force have achieved conservation in its fullest meaning—not a conservation of hoarding, not a conservation of non-use, but a positive conservation that consists in finding, developing, and making available for public use an ever increasing supply in orderly response to growing needs.

By its very nature, this conservation cannot remain static. It nourishes its own growth and thrives on its output. It carries an inherent drive that spurs it forward. This drive comes in part from the environment within which it has developed. Its stimuli are incentive and opportunity. It is activated by competition and expands through freedom.

Conservation has not always been a characteristic of petroleum production. Indeed, inefficient extraction and both physical and economic waste were typical of the production process for many years. The supply was on a precarious basis and was continuously threatened with dissipation. That situation no longer prevails. Within the past quarter century there has taken place a technologic revolution in the process of oil production. Extensive research and experimentation have reduced to a practical working science the efficient recovery of oil and gas from underground reserves, and the supply today rests on a firm foundation of many pools whose production is regulated in accordance with scientific requirements to assure efficient extraction.

Why, then, are we concerned today with conservation? The answer lies in the abnormal conditions that confront us. World-wide dislocations have placed upon the material and industrial wealth of the United States a tremendous burden. So essential is petroleum that its continued supply in adequate quantity is a matter of the utmost importance, not alone from the standpoint of our comfort and convenience, but our very security. It behooves us, therefore, in spite of the record of accomplishments, to appraise the status of our supply, to analyze the methods employed to conserve it, and to develop the basis on which our petroleum industry can, through its continued efforts, achieve still greater conservation.

This volume is primarily directed to two interested groups in whose hands lies the further development of conservation: the petroleum industry, including its royalty owners, and the government (national, state, and local, including law-making bodies, courts, and administrative agencies). For the former, the volume is a technical treatise on conservation and the mechanics of efficient recovery; for the latter, it sets forth the principles underlying conservation and the reasons for certain practices to achieve it. It is hoped that this volume will help point the way for further enlightened action in improving the legal and administrative framework within which the industry can itself advance conservation. To a great degree conservation of petroleum has been and must remain a cooperative process. The technologic progress leading to it has come primarily from within the industry. It is significant that it has reached its highest state in the United States, where it thrives under a flourishing competitive system, and not in those parts of the world where oil is produced by instruments of the state. The present system of conservation has been developed, however, within a framework of sound laws and practices designed for its intelligent regulation.

Although this volume is directed to those immediately concerned, the public, through the myriad advantages of a continuous, adequate, and stable supply of petroleum products and a vigorous industry is the ultimate beneficiary of conservation.

THE CONTRIBUTORS

This volume, like the subject with which it deals, required the cooperative effort of many people. It represents a departure from the usual practice of preparation either by a single author or by various authors whose writings appear as separate chapters individually prepared. Instead, the attempt throughout this book has been to weld together into a single continuous whole the individual contributions on many subjects. Each contributor was asked to submit material on particular topics with the understanding that the final manuscript would be the responsibility of the Editorial Committee and that no author need feel responsible for any specific statements appearing in the volume. Accordingly, participation as contributors does not signify that those listed subscribe to or support any viewpoint expressed.

With the exception of Chapter III, which was generously contributed in its entirety by Dr. K. C. Heald (Gulf Oil Corporation), this plan was followed, and the manuscript, except for Chapter III, was prepared by the editor from these contributions and from other material from both published and unpublished sources. The Committee takes this opportunity to acknowledge its deep gratitude to Dr. Heald and to the following additional contributors:

Stewart P. Coleman—Standard Oil Company (N. J)., with the assistance of E. S. Neal and E. F. Sibbern

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In addition, the Committee wishes to make special mention of the contribution of Robert E. Hardwicke of the Fort Worth, Texas, bar. Mr. Hardwicke agreed to write for this volume a chapter dealing with legal problems, but so much material was available that the manuscript grew larger and larger, presenting real difficulty in limiting adequate discussion to chapter length. It was then proposed to Mr. Hardwicke that the manuscript be completed for publication as a separate book, tracing, especially from a legal viewpoint, the conservation movement in which Mr. Doherty was a potent influence, but pointed toward the history of unit operations and the effect of antitrust laws on such operations. That has been done. The book, amply documented, was published by the Institute in 1948 under the title, *Antitrust Laws, et al. v. Unit Operation of Oil or Gas Pools*. It is a companion volume to *Petroleum Conservation*.

A volume of this sort would not have been possible at all were it not for the work of the many geologists, engineers, and others who have contributed through their research and field studies to the technology of petroleum production. Their contributions, particularly those recorded in the published literature, have been drawn on extensively in its preparation.

The editor wishes also to express his personal appreciation to Dr. W. V. Vietti, not only for his direct contribution, but for his assistance and counsel from the preparation of the first outline to the completion of the final manuscript; to his own staff of Humble Oil & Refining Co., including, in particular, Dr. C. R. Hocott and Mr. R. C. Craze, whose advice and criticism were most helpful; and to those many others who reviewed the preliminary manuscript and offered constructive suggestions.

STUART E. BUCKLEY

Houston, Texas
June, 1951

CONTENTS

PREFACE by J. M. Lovejoy, E. DeGolyer and W. A. Sinsheimer .. vii

INTRODUCTION xi

Chapter I

ELEMENTS OF CONSERVATION 1

Chapter II

PETROLEUM RESOURCES 15

Part One . . . OIL RESOURCES 15

Part Two . . . NATURAL GAS RESOURCES 29

Chapter III

THE PETROLEUM RESERVOIR 47

Chapter IV

CHARACTERISTICS OF RESERVOIR FLUIDS 85

Chapter V

FUNDAMENTALS OF OIL RECOVERY 117

Chapter VI

EFFICIENT OPERATION OF PETROLEUM RESERVOIRS 141

Part One . . . OIL RESERVOIRS 141

Part Two . . . GAS RESERVOIRS 175

Chapter VII

SECONDARY RECOVERY 182

Chapter VIII

PRESSURE MAINTENANCE 196

Part One . . . OIL RESERVOIRS 196

Part Two . . . GAS RESERVOIRS 242

Chapter IX

CONSERVATION AND STATE REGULATION 248

Chapter X

COOPERATIVE DEVELOPMENT AND UNIT OPERATION 276

FIGURES

Fig. 1-A—Bedding Planes in Limestone 53

Fig. 1-B—Cross Bedding in Sandstone 53

Fig. 2—Joints in Sandstone 54

Fig. 3—Water Encroachment, Reed City Pool 56

Fig. 4—Cross Section of the Sugarland Field Showing Position of Edge Water 72

Fig. 5—Cross Section of the Amelia Field Showing Oil Pool Underlain by Bottom Water 73

Fig. 6—Cross Section of Crescent Field Showing Three Reservoir Rocks with Common Water Level 82

Fig. 7—Illustrative Phase Diagrams 88

Fig. 8—Effects of Reservoir Pressure Decline on Properties of Reservoir Oil and Gas 100

Fig. 9—Effect of Dissolved Gas on Formation Volume of Reservoir Oil 101

Fig. 10—Phase Diagrams of Typical Reservoir Gases 104

Fig. 11—Water-Flood Process 189

Fig. 12—Reservoir Pressure Decline for Constant Rate of Water Influx 203

Fig. 13—Cumulative Water Influx for Constant Pressure Difference 203

Fig. 14—Effect of Structure on Gas-Oil Ratio 219

Fig. 15—Effect of Water Drive on Oil Migration 239

TABLES

Table 1—United States Crude Oil Production and Reserves 16

Table 2—A.P.I. Estimates of Proved Reserves—United States, Period 1937-1950 18

Table 3—Estimated Proved Reserves of Crude Oil in the United States by States 19

Table 4—Fundamental Position of Crude Oil Producing Industry—United States 20

Table 5—Exploratory Activity and Discoveries—United States 24

Table 6—Well Completion Data and Estimated Development Costs 25

Table 7—Estimated World Demand for Oil 27

Table 8—Production and Estimated Proved Reserves by Major Oil-Producing Regions of World 28

Table 9—Gross Production and Disposition of Natural Gas in the United States, by States, in 1949 32

Table 10—Estimated Proved Recoverable Reserves of Natural Gas in the United States 34

Table 11—Summary of Estimates of Natural Gas Reserves, 1919-1950 35

Table 12—Estimated Proved Recoverable Reserves of Natural Gas Liquids in the United States 38

Table 13—Annual Production Petroleum Liquids and Natural Gas, 1946-1950 38

Table 14—Comparison Low-Pressure and High-Pressure Horizontal Gas Drive 231

Table 15—Effect of Migration on Relative Oil Recoveries of Various Properties 240

CHARTS

Chart I—Annual Record of U. S. Reserves 21
Chart II—Production and Discovery History, United States 23
Chart III—Natural Gas Marketed and Oil Consumed, United States 31
Chart IV—Estimates of Proved Reserves of Natural Gas, United States 36
Chart V—U. S. Mineral Fuel Consumption 44

Chapter I

ELEMENTS OF CONSERVATION

THE PETROLEUM INDUSTRY

Continuous Exploration and Development Provide the Basis

In the minds of many, the present supply of petroleum appears to be an obvious reflection of the fact that large oil and gas reserves have been discovered in the past, and the petroleum industry is presumed to have come into being for the purpose of liquidating those reserves to meet the demand. Correspondingly, conservation is frequently thought to imply simply the saving of part of the reserves to meet possible future needs. This erroneous concept, together with the false corollary that conservation consists merely in hoarding, arises from the fact that the petroleum industry is a mineral industry, engaged in the exploitation of a natural resource, and the further premise that all mineral resources are irreplaceable. True it is that oil and natural gas are not replaced by natural geologic processes at a rate sufficient to maintain a commercial supply; nevertheless, the petroleum industry is not one occupied simply in liquidation. Taken as a whole, it is a business enterprise engaged in the continuous discovery, development, and harvesting of new sources of supply. The proved reserve of petroleum, the mineral store discovered and proved by past drilling, constitutes the working stock that is drawn on continuously for the daily supply. This stock must be maintained through continuous exploration and new drilling.

Developed Reserves Control the Rate of Supply

The physical nature of oil reservoirs is such that the oil cannot be withdrawn instantaneously. Although the rate of withdrawal from any reservoir is subject to control and can be increased or decreased, there is, nevertheless, a definite upper limit to the rate at which any oil field can be produced efficiently; there are both upper and lower limits to the rate at which it can be produced economically; and there are absolute physical limitations on the rate at which it can be produced even if all considerations of efficiency and economics are abandoned. As a practical matter, therefore, the size of the known and developed oil reserve at any time controls in large measure the *rate* at which oil can be produced, but does not control the duration of time the supply will last. For example, at the end of 1914 the discovered oil reserves in the United States are now known to have totaled slightly over 7 billion barrels. During the thirty-five year period from 1914 through 1949 the United States produced over 35 billion barrels of oil. Although the production during the interval was approximately fivefold as great as the reserve at the beginning, the estimated proved reserves of crude oil on December 31, 1949, totaled over 24 billion barrels. It is obvious that the developed reserves in 1914 had only a minor bearing on the supply during the subsequent years. Also, their contribution to present production is nil.

Continuity of Supply Depends on Exploration

It is clear from this record that the future supply of petroleum is determined not so much by past discoveries as by current and future discoveries. The known reserve at any time fixes merely the possible withdrawal rate at that time; continuity of supply is dependent on exploration. Exploration and development drilling, in turn, are financed primarily by the profits derived from current production. Since the relationship between current demand and current supply largely controls the price of either oil or gas, supply and demand are usually kept in reasonable balance by the normal working of economic forces, especially with respect to oil. A tendency of supply to lag behind demand because of too low a developed reserve tends to raise prices and profits and thus to accelerate exploration and development, which increases the reserve and makes a higher rate of supply available. Conversely, new discoveries and rapid development of large new fields or groups of fields have at times made temporarily available an excessive supply, which has resulted in depressed prices, either locally or nationally, and caused a reduction in exploration activity. Heretofore, the primary demand has been for oil, not gas. Since gas is nearly always associated with oil and is necessarily produced with it, and since gas reserves are often discovered in the search for oil, an excessive supply of gas does not have the same effect on total exploration activity as is the case with oil.

THE FUTURE OUTLOOK

What is the outlook for petroleum?

It is evident from the history of past production that the future supply of petroleum must come primarily from tomorrow's discoveries. Discoveries, in turn, result from the availabilty and use of venture capital. In essence, therefore, the future continuity of the supply of petroleum and its products is directly dependent upon the industrial and financial health and vigor of the petroleum industry. In this respect the petroleum industry is typical of all other American industries, and the supply of petroleum, like the supply of all other commodities, depends upon there being an adequate margin of profit on the invested capital.

How long will our petroleum last?

Since the petroleum industry is engaged primarily in making products available through a continuous search for and development of new supplies, the supply will obviously dry up and vanish only if one of the following two things should happen:

a. All the raw material be discovered and consumed, and no more be available to be found.

b. Prior to discovery of the ultimate total supply of raw material, the search for and exploitation of new deposits become unprofitable.

Categorical answers cannot be given to the question of when, if ever, either of these conditions might come about.

The Raw Materials

To explore the first condition, the possible complete exhaustion of the raw material, it is necessary to consider what petroleum is and whence it comes. Basically, and in its simplest forms, petroleum consists of liquid crude oil and natural gas, both produced primarily as fluids from wells. To the extent that oil and natural gas are used as fuel, petroleum represents but one of many sources of power. The question might, therefore, be broadened still further to a consideration of the continuity of adequate and economical power supplies. At this stage, however, the future becomes indistinct, the issues being controlled by the possibility, speculative rather than demonstrated, that power from atomic fission may become a major industrial factor. An exhaustive long range forecast of the future role of the petroleum industry in our industrial economy would require consideration of such broader aspects.

Considered in another light, both crude oil and natural gas are preponderantly hydrocarbons, materials composed of the elements carbon and hydrogen. To the consumer these materials are fuels, lubricants, solvents, plastics, and organic chemicals, with fuels and lubricants predominating. The petroleum industry may be considered, therefore, as one engaged in supplying fuels and lubricants, along with certain specialties, by the discovery, production, and processing of raw materials. Hydrocarbons constitute today the bulk of our liquid and gaseous fuels and lubricants. Crude oil and natural gas are today the cheapest and therefore most readily available source of these hydrocarbons. However, they constitute by no means the sole source or the only potentially available source. Large deposits of hydrocarbons are known in proved reserves of asphalt, oil shales, tars, and other naturally occurring forms. Deposits of these materials constitute an ultimate hydrocarbon reserve. They are exploited on only a small scale because today the exploration for and production of liquid crude oil and natural gas and their processing into products provide a cheaper supply. When this condition no longer exists, secondary hydrocarbon reserves can be exploited.

Synthetic production of hydrocarbons from carbon and hydrogen constitutes an additional potential source of liquid hydrocarbon fuels and lubricants. Hydrogen from steam and carbon from coal provide the most readily apparent source of this auxiliary reserve. Synthetic fuels and lubricants from hydrogen and coal constitute a proved potential reserve, but have been produced commercially only locally where, through economic or other causes, ample supplies of liquid crude oil and natural gas have not been available. The largest exploitation of such a secondary reserve to date was in Germany during World War II.

The interchangeability of crude oil, natural gas, oil shales, and coal, not as different fuels, but in the form of equivalent and even identical fuel and lubricant end products, is no longer a speculative hope; the scientific and industrial know-how exists today for the conversions on a commercial scale. These auxiliary materials must be considered, therefore, as part of the supply of raw material. Since the proved reserves of coal alone are adequate for many centuries, complete exhaustion of the raw material will not in itself limit the supply of "petroleum" products in the foreseeable future. Although an ultimate and continuing supply may thus be assured on one count, it is to be expected that sudden surges of demand might produce temporary shortages should such surges occur at a time when the maximum rate of availability of the supply is in close balance with the normal demand.

From the standpoint of the consumers' demands for liquid and gaseous hydrocarbon fuels and how these demands are to be met in the future, the situation may be summarized as follows:

For the present and at least the immediate future, proved domestic reserves of oil constitute a sufficient working stock to maintain a rate of supply equal to or exceeding current United States production. Discovery rates, including extensions proved by development drilling, have consistently exceeded production. Imports of crude oil and products constitute a currently available supplemental source. Developed reserves of natural gas exceed the requirements to meet the present withdrawal rate. Plants for conversion of methane, of which natural gas is largely composed, into liquid hydrocarbons have been designed, and one such plant is in operation. Our natural gas reserves constitute a supplemental supply of crude-oil equivalent. Further conversion of methane can take place whenever the increasing costs of finding and producing crude oil bring methane conversion to the level of being economically competitive.

Future costs of finding and producing crude oil may be expected to follow, with possible interruptions, a gradually increasing trend as wells are drilled deeper and as oil becomes harder to find. The resultant increases in the price of crude oil should bring gradually an increasing rate of conversion of natural gas, and, eventually, conversion of solid hydrocarbons, oil shales, and coal. Under the cost and transportation differentials from one part of the country to another, local development of different sources of secondary supplies of hydrocarbons may be expected to proceed to some extent simultaneously.

KEY TO THE FUTURE IS A VIGOROUS INDUSTRY

Because of the tremendous reserves of auxiliary sources, the supply of petroleum in the form of products will not disappear in the foreseeable future as a result of exhaustion of raw materials; hence it could fail only through the second possible cause, i.e., lack of profit in the venture, or, in other words, collapse of the petroleum industry. Under normal conditions such failure would be unthinkable. As oil reserves become increasingly difficult to locate and more expensive to develop they will probably be supplemented by imports of foreign oil, by conversion of natural gas, and, gradually, by conversion of the other basic raw materials on a growing scale. Increasing costs and reduction of profits from oil and gas production, and competition to supply fuels and lubricants should dictate the rate and direction of use of supplemental sources of raw materials. No sudden cessation of crude oil production is envisioned in any event. The nature of oil fields is such that they cannot be depleted at will but must inevitably be produced for years before they become exhausted. It is to be expected, therefore, that the future supply of hydrocarbons will eventually pass through a prolonged transition, during which multiple sources of basic raw materials will be simultaneously used.

It is not the purpose of this volume to explore the future stability of the American system of private enterprise or the financial prospects of the petroleum industry in its many branches. Rather, its limited purpose is to probe and explain the basic essentials of conservation in the special field of production of crude oil and natural gas. The background presented is for the purpose of acquainting the reader with the basic facts concerning our petroleum supply and its utter dependence upon a healthy industry.

Intimately related to the need for a continued healthy industry is the conservation of that petroleum already discovered and to be discovered in the future. Conservation is not hoarding; the needs of our economy today and in the future will not be met by hoarding or non-use of our petroleum resources. Conservation consists in the prevention of reasonably avoidable physical waste, underground and aboveground, in efficient recovery and processing, in increasing the yield.

THE COMMON INTEREST IN CONSERVATION

Rising Costs Provide the Incentive

It should be readily apparent that conservation of petroleum involves no essential diversities of interest between the public and a competitive petroleum industry actuated by the profit motive. Analysis of present and future sources of the supply of petroleum products and their equivalents clearly shows that each successive source will be more costly for a barrel of product than its predecessors, products from crude oil being cheaper to produce than equivalent products by conversion of natural gas, oil shale, and coal. Furthermore, it will be the rising costs of production, as crude oil becomes more difficult to find and must be produced from greater depths, that will eventually force the introduction and development of secondary sources of supply. Thus, the long term future trend, regardless of the source of supply, will be one of rising costs. Under that condition, each unit in a competitive industry will be forced to strive for reduced costs through greater efficiency. The most obvious direction in which to reduce future costs or to postpone their rise is to increase and prolong the supply of the cheapest source of raw material, petroleum. Thus, there exists a tremendous incentive to increase the ultimate recovery of oil from reserves already discovered and developed, and from those yet to be discovered, rather than to squander those reserves through inefficient production practices. Inefficient recovery would require replacement of the unrecovered oil by new reserves, increasingly more difficult to discover, increasingly more expensive to develop.

(From the standpoint of the public, the recovery of a higher percentage of the oil from existing reserves keeps costs of products at a minimum and safeguards supply.) Auxiliary benefits include continuity of employment and income in oil-producing regions, and continuity of tax revenue.

(Thus, conservation, as applied to petroleum production, is a business necessity under a competitive system. Both the petroleum industry and the public share its benefits.)

BASIC CAUSES OF WASTE

In order to understand how increased recovery of petroleum is achieved it is necessary to know the manner in which oil and gas are produced and how the amounts recoverable from an underground reservoir are affected by production practices. It is also essential, because of the peculiar problems that arise from the fluid nature of oil and gas, to understand certain elements of the legal and administrative environment in which the production branch of the petroleum industry operates.

Although the Federal Government owns large land areas in many states, most of the land area in the United States is owned by individuals. As a part of the land, the minerals, including oil and gas, are largely privately owned. Oil and gas wells are usually drilled on land leased from the owner, who receives a royalty, usually a fraction of the production or of its value. The leasing of land for exploration and development of oil and gas reserves, whether from private landowners or from the state and federal governments, is a matter of contract between the oil producer and the landowner. The contract is in the form of an oil and gas lease. In the usual oil or gas field there are many landowners and many lessee-producers. Seldom is an entire oil field contained within land belonging to a single owner and leased in its entirety by a single producer.

CONFLICTS OF INTEREST ARISING FROM FLUID NATURE OF OIL AND GAS

Unlike the solid minerals, oil and gas, being fluid, are not confined during production to their original underground location. They migrate to producing wells without regard to lease or ownership boundaries. Thus, in the competitive development of an oil pool, each producer and each royalty owner must assure himself of protection of his underground supply of oil or gas against adverse effects that might be caused by production of his neighbors' wells. Because of the impossibility of identifying the particular oil or gas issuing from a well with the particular land under which it might originally have been located, the courts many years ago established the principle that, although the minerals are a part of the land, the owner of a tract has the right to drill wells on it, and he owns the oil and gas produced from his wells, even though that oil and gas might be drained from under lands of his neighbors. In the complete absence of any kind of regulation or of any agreement among all the producers and royalty owners in a pool, it is obvious that once an oil pool is discovered a competitive race to drill wells and produce the oil is a practical necessity, for the owner who lags in drilling, or who fails to get as much oil from his wells as his neighbors produce from their wells, will lose oil by subsurface drainage to adjacent properties. If he is a lessee he may also be liable to his lessor for damages by failure to act as would a reasonably prudent operator to protect against adverse drainage. Lack of either regulation or cooperation thus leads inevitably to a chaotic condition in the development and production of any newly discovered reserve.

Prior to the development of modern conservation techniques each new pool was drilled and exhausted as rapidly as was physically possible in the effort by each producer to get his oil to the surface and reduced to possession, whether or not a market existed for the oil. Waste was inherent in the manner of production and was inevitable, both underground and at the surface. Oil that could not be absorbed by current demands had to be stored, usually for a long period, and frequently in earthen pits. Fire, leakage, evaporation, and deterioration took a severe toll. Prices were periodically depressed to absurdly low levels, business and employment were disrupted, and cheap oil was squandered. Underground loss of oil was tremendous, for only that oil was recovered that would flow readily into a well under immediately available underground forces, the remainder being left in the ground. The natural gas associated with the oil was blown to the atmosphere and burned, for conditions did not permit its recovery and utilization. Boom towns were created overnight and as quickly vanished, leaving only their scars; there resulted no stability of employment, no stability of income to build permanent communities.

Regulation Needed

This waste, with its resultant uncertainty of supply, was not in the public interest and not in the best interests of oil producers. It was protested against by leaders in and out of the petroleum industry. The situation was one that obviously called for remedy, but thoroughly effective remedial measures were not possible until there had been developed sufficient technologic understanding of the behavior of oil and gas pools to determine the basic causes of waste and how to prevent it. As this understanding grew it became apparent that one of the fundamental causes of waste was "wide open" or unrestricted production. It became equally apparent, however, that because of the multiplicity of ownership in most oil and gas fields and the resultant conflicts of interest, efforts of individual producers alone could not effectively bring about conservation. Imperative necessity existed for a system of law and order under which oil and gas could be produced in an efficient manner and under which a better method than unrestricted drilling and production would be provided to protect property rights.

A REGULATED CONSERVATION SYSTEM

To a large extent the problems have been solved. There exists now a system of oil and gas conservation based on sound engineering principles. In most of the important oil-producing states this system rests on state statutes defining and prohibiting waste, and is administered through state regulatory agencies. These statutes and regulations are supported by court decisions. Under this system it is possible both to achieve conservation of oil and gas and to give reasonably adequate protection of property rights in oil and gas pools.

CONSERVATION A COOPERATIVE PROCESS

How is waste prevented?

The prevention of waste in production operations has become a cooperative process, requiring the simultaneous interaction of a number of essentials. Each individual producer owes the duty so to develop and operate his property as to prevent waste and respect the rights of his neighbors. However, because of the behavior of oil and gas in underground reservoirs, *responsibility* for prevention of waste also rests with the states; *authority* for its prevention exists in the police power of the states; *incentive* for its prevention lies in the reduced costs and greater ultimate income that results from increased recovery. For effective conservation these factors must be brought together in such manner that through sound regulation, administered in the light of thorough technical understanding of the processes of oil and gas recovery, each producer may so operate his property as to achieve the highest possible ultimate recovery and at the same time enjoy adequate protection of his property rights.

THE TECHNICAL AND ADMINISTRATIVE REQUIREMENTS

The basic technical concepts underlying the prevention of waste are dealt with in detail in subsequent chapters of this volume. Their essence is as follows:

Control of Production Rate

Unrestricted or "wide open" production of oil causes premature dissipation and inefficient use of the expulsive forces residing in an oil reservoir. Exhaustion of the reservoir pressure prior to recovery of the oil leaves unrecovered a large part of the original reserve.

The first technical requirement of conservation is, therefore, that the rate of production of each oil reservoir be restricted in sufficient degree to permit proper and efficient use of the expulsive forces available within the reservoir. Here arises the first and most urgent requirement for regulation by the states. Unilateral action by a single producer in restricting his own production in a competitive pool would not be effective, for some of the oil and gas underlying his property would drain to the unrestricted wells of his competitors. Moreover, in most cases he has a legal obligation to protect his lessor against drainage. Voluntary cooperative action among all the producers within a given pool to restrict production is difficult to bring about, partly because of legal implications. The direct and obvious solution is for the states to restrict production to such degree and in such manner as to permit efficient exploitation of each reservoir. Subject to the necessities of waste prevention, the regulation should, within reasonable limits, give each producer the opportunity to obtain his fair share of the production from a common pool.

Control of the Reservoir

Restriction of production alone is not sufficient to guarantee efficient recovery. Not only must the rate of production be restricted in order to permit efficient use of the expulsive agents available in a reservoir, but auxiliary regulations must be employed that specifically prevent the excessive and premature dissipation of these agents. Here again any regulation should be reasonable and should not unnecessarily cause injury or result in discrimination.

Restriction of Total Production to Market Demand

Control of the rate of production and of the naturally available displacing agents of a reservoir might normally be considered to be sufficient to guarantee efficient recovery of an oil reserve. However, a third basic and important requirement arises when the total market demand for oil from a state is less than the aggregate efficient producing capacity of the fields. When that situation arises it becomes essential, in order to prevent waste, to invoke a still further restriction, to limit the total production to market demand. This phase of regulation by the states is perhaps the least understood.

It is reasonably obvious that if oil is produced in excess of market demand the unconsumed production will be stored above ground, where it is subject to loss through fire, leakage, evaporation, and deterioration. Such losses constitute above-ground waste. However, one of the chief reasons for the restriction of production to market demand is that such restriction is necessary to prevent underground waste of oil. It is this feature that is less commonly understood. A corollary element is that, in order to prevent underground physical waste in the form of reduced ultimate recovery, it is necessary in any restriction of production to provide concurrently a system that will cause ratable withdrawal of the oil from a common reserve.

Experience has demonstrated that when the market demand for oil is less than the amount that can be produced at efficient rates, a conservation agency cannot bring about ratable production unless it has the authority to limit production to the demand. The market demand is the aggregate amount of oil required to meet current needs for consumption and storage. It is the amount that purchasers are willing to buy. They cannot be required, by administrative order, to buy more than they want. Because there are usually multiple purchasers within a given pool, the burden of assuring ratable takings and protecting property rights of the individual operators, if the allowed production exceeds the amount that purchasers are willing to buy, is shifted from the regulating agency to the purchasers. Unless the purchasers can act in unison in such manner as to provide proportionate takings from all of the producers, a situation usually arises in which some producers can produce and sell a greater share of the permitted production from their wells than their neighbors can, and may thus drain oil underground from their less fortunate neighbors. Conditions arise that, to some degree, are similar to those encountered in completely unrestricted production. Producers in less fortunate market positions may be forced to erect unnecessary storage and to produce oil into such storage to avoid loss through underground drainage, or, in the event that it is uneconomic to erect such storage, may be forced to suffer loss through drainage. Unequal withdrawals within a reservoir may lead to inefficient use of the displacing forces at work in producing the oil. Such conditions undermine the effects of regulations based solely on the technical factors involved.

A secondary effect of production in excess of market demand is that it usually causes distress prices, which, in turn, may make unprofitable certain production practices required to increase recovery. Distress prices may also cause the premature abandonment of wells of low capacity, with resultant loss of ultimate recovery.

It is clear from these various considerations that production materially in excess of the reasonable market demand for an extended period of time results in physical waste, above ground and underground. It also leads to drainage of neighbors' lands by some operators. These evils can be avoided by restricting production so that it will not exceed the reasonable market demand, and by properly allocating the allowed production to the various pools and producers.*

REQUIREMENTS FOR FUTURE IMPROVEMENT

Great strides have been made in the conservation of oil and gas during the past twenty years. The conservation system that has been developed is well balanced, and experience has proved it workable. In essence, conservation in most of the important oil-producing states is achieved through a cooperative arrangement in which the state provides the rules and acts as umpire, but the producers, through their own initiative, develop the mechanical and technical improvements that support progress. This flexible system permits and encourages adoption of efficient recovery practices.

Great as the achievements under this system have been, they by no means represent the attainment of perfection. Conservation has come a long way—it has a long way yet to go. The future need is not a new system but a continuation of the progress that has characterized the past. Stagnation is fatal in a competitive system; fortunately, it has never been a characteristic of the American petroleum industry. Competition has fostered innovation and a striving for ever increasing efficiency. These must be continued in the future.

The requirements for future progress can be reduced to two basic essentials, both of which can be provided through the conservation framework now in existence. These essentials are as follows:

1. The development of new and improved recovery techniques. These stem from research and experiment and from technical analysis of field experience. Their chief source in the future as in the past must be the industry itself. Research in universities, by the United States Bureau of Mines, and in research foundations supported by industry play an important auxiliary part.

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*The reader who is especially interested in this aspect of conservation will find the subject of restriction of production to market demand and the necessity for such restriction to prevent waste dealt with more fully in a statement by Harold B. Fell, beginning at page 1,830 of Part 4 of Hearings before a Subcommittee of the Committee on Interstate and Foreign Commerce, House of Representatives, 76th Congr., 3rd Sess., on H. Res. 290 and H. R. 7372 (Feb. 1940), and in a statement by Robert E. Hardwicke, beginning on page 1,480 of the same Hearings. The subject is also discussed by Hardwicke, beginning at page 222 of *Legal History of Conservation of Oil and Gas, A Symposium* (1939) and in *Market Demand as a Factor in the Conservation of Oil,* a paper prepared for Legal Institute on Oil and Gas, sponsored by the Southwestern Legal Foundation, Dallas, Texas, March 23, 1949; and by Hines H. Baker in *Achievements and Unsolved Problems in Oil and Gas Conservation,* a paper presented before the Spring Meeting of the Southwestern District, American Petroleum Institute, Division of Production, at Galveston, Texas, March 10, 1949.

2. The rapid adoption of improved techniques as they are developed. This must come through effective communication, cooperation, and intelligent and flexible regulation.

The key to the whole is cooperation, among producers, between producers and royalty owners, between the industry and state regulatory agencies, and among the states.

Subsequent chapters of this volume will show that efficient recovery from an oil or gas pool can best be assured when all producers therein cooperate to adopt and carry on jointly the most effective recovery method for the entire pool. Cooperation requires that the technical information related to improved recovery procedures developed by one be imparted to others. Improved procedures cannot be used effectively unless they are known and understood by all. This poses a particularly difficult and challenging task for the petroleum industry. Its complex make-up; the tremendous number of individual competitive producers; the vital interests of the myriad royalty owners, many with no understanding of the technical requirements of efficient recovery practices; legislative bodies, courts, and administrative agencies, who must be thoroughly informed, not just as to broad aspects but as to technical details as well—all have an effect, direct or indirect, on recovery methods.

Effective channels of communication exist. At the technical level, the professional societies fill a vital role as forums for the exchange of scientific information. The Petroleum Branch of the American Institute of Mining and Metallurgical Engineers, and the American Association of Petroleum Geologists and its affiliated societies have played an important part in this activity. At the industry level, producers' associations have provided avenues for the exchange of both technical information and the results of field experience. The many technical committees of the American Petroleum Institute have contributed materially to progress. Essential basic facts concerning specific fields are acquired and exchanged through operators' committees and engineering committees in various areas. At the state level, the Interstate Oil Compact Commission, with its engineering, research, and other committees, is an effective instrument for exchange of information between the regulatory bodies of the various states and between industry and the state agencies. The various trade publications carry information to many.

The framework, the avenues of communication, and the instrumentalities for cooperation all exist. The task for the future is their continued and more effective use.

Chapter II

PETROLEUM RESOURCES

Part One . . . OIL RESOURCES

CUMULATIVE OIL PRODUCTION AND ESTIMATED RESERVES—UNITED STATES

The United States has produced, through the year 1950, a total of over 40 billion barrels of crude oil during the 90 years since the first oil well was drilled in this country. Annual crude oil production first reached the 100 million barrel mark in 1903 and touched a billion barrels yearly in 1929. The billion barrel yearly production was not reached again until 1936, but subsequent production increased steadily to an all-time high of 2,020,185,000 barrels a year (5,520,000 barrels daily) in 1948. Present rates of production indicate that this amount may be exceeded during 1951.

An estimate of crude oil reserves made by the United States Geological Survey in 1922 indicated the discovered reserves in the United States at that time to be 5 billion barrels. From 1922 to 1936 occasional estimates of reserves are on record, but it was not until 1936, when the American Petroleum Institute commenced an annual survey of estimated proved reserves, that regular annual estimates became available. The estimated proved reserves reported by the A.P.I. at the end of the year 1936 amounted to 13,063,400,000 barrels, and since that time have increased to 25,268,398,000 barrels at the end of 1950.

Table 1 gives the annual crude oil production of the United States by years from 1900 through 1950, and estimates of reserves, where available, as of the end of each year.

The estimates of proved reserves are revised annually on the basis of the information obtained through additional exploration, development, and production. The estimated proved reserves are increased through the discovery of new pools and the extension of known fields through additional drilling. The estimated reserves of a particular pool may be increased or decreased by revisions based on additional information obtained during the year from additional drilling and further production history. The reserves are, of course, reduced by the amount of oil produced during the year.

TABLE 1

United States Crude Oil Production and Reserves

	Annual[*] Crude Oil Production	Estimated Year End Reserves	
Year	1,000's of Barrels—42 U.S. Gallons		Source of Reserve Estimate
1859–1899	939,984		
1900	63,621		
1901	69,389		
1902	88,767		
1903	100,461		
1904	117,081		
1905	134,717		
1906	126,494		
1907	166,095		
1908	178,527		
1909	183,171		
1910	209,557		
1911	220,449		
1912	222,935		
1913	248,446		
1914	265,763		
1915	281,104		
1916	300,767		
1917	335,316		
1918	355,928		
1919	378,367		
1920	442,929		
1921	472,183		
1922	557,531	5,000,000	U.S. Geological Survey
1923	732,407		
1924	713,940		
1925	763,743	5,321,000	A.P.I. Committee of eleven
1926	770,874	4,500,000	Federal Oil Conservation Board
1927	901,129		
1928	901,474		
1929	1,007,323		
1930	898,011		
1931	851,081		
1932	785,159	10,000,000	Federal Oil Conservation Board
1933	905,656	12,000,000	Valentine Garfias, Petroleum investigation hearing on H. Res. 441
1934	908,065	12,177,000	American Petroleum Institute
1935	996,596		
1936	1,099,687	13,063,400	American Petroleum Institute
1937	1,279,160	15,507,268	American Petroleum Institute
1938	1,214,355	17,348,146	American Petroleum Institute
1939	1,264,962	18,483,012	American Petroleum Institute
1940	1,353,214	19,024,515	American Petroleum Institute
1941	1,402,228	19,589,296	American Petroleum Institute
1942	1,386,645	20,082,793	American Petroleum Institute
1943	1,505,613	20,064,152	American Petroleum Institute
1944	1,677,904	20,453,231	American Petroleum Institute
1945	1,713,655	20,826,813	American Petroleum Institute
1946	1,733,939	20,873,560[†]	American Petroleum Institute
1947	1,856,987	21,487,685[†]	American Petroleum Institute
1948	2,020,185	23,280,444[†]	American Petroleum Institute
1949	1,841,940	24,649,489[†]	American Petroleum Institute
1950	1,943,776	25,268,398[†][‡]	American Petroleum Institute
Total Production 1859–1950	40,889,290		

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[*] Annual crude oil production figures from U.S. Bureau of Mines, except for 1950, which is from A.P.I.

[†] Not strictly comparable with years prior to 1946 due to the exclusion of reserves of cycle-plant and lease condensate, amounting to 884,967,000 bbls. on 12/31/45.

[‡] On December 31, 1950, the American Petroleum Institute reported 4,267,663,000 bbls. of proved reserves of natural gas liquids additional to the crude oil reserve of 25,268,398,000 bbls., giving a total liquid hydrocarbon reserve of 29,536,061,000 bbls. on that date.

The net change in estimated proved reserves for the year is equal to the aggregate amount added through new discoveries, extensions, and upward revisions of the estimates for older pools less the amount of oil produced during the year and less any downward revisions of the estimates for older pools.

During the fourteen-year period for which the A.P.I. annual reserves reports are available nearly 7 billion barrels of reserves have been added through additions classified by the A.P.I. as new discoveries, and over 28 billion barrels have been added through additions classified as revisions of previous estimates and extensions to known fields, including revisions and extensions for fields discovered during the period. These total additions of approximately 35 billion barrels during the fourteen years exceeded by 13 billion barrels the production of 22 billion barrels during the same period, resulting in estimated proved reserves increasing nearly twofold from 13,063,400,000 barrels at the end of 1936 to 25,268,398,000 barrels at the end of 1950. (The discrepancy between the increase of estimated proved reserves and the excess of discoveries and additions over the production for the interval is accounted for by the fact that up to December 31, 1945, certain liquids from condensate wells and gas-cycling plants were included with crude oil reserves. Thereafter reserves of natural gas liquids were separated from crude oil reserves.)

Table 2 summarizes the A.P.I. estimates of proved reserves for the years 1937-1950, and Table 3 gives the A.P.I. estimates of proved reserves by states as of the end of the year 1950.

During the period 1936-1950, additions to estimated proved reserves classified as revisions of previous estimates and extensions to known fields were approximately 4.2 times as large as additions through reported new discoveries. This emphasizes the importance of revisions and extensions in carrying forward estimates of proved reserves each year. Large additions through revisions and extensions are unavoidable in the conventional procedure for estimating proved reserves. This is because the reserves represent oil actually in sight in proved areas of fields. The large volume of revisions and extensions reported each year results from the fact that it is impossible to evaluate a new discovery fully during the year in which the discovery is made. The true amount of reserves in any field cannot be determined until the size and characteristics of the productive reservoir have been completely defined by development, which usually requires several years.

TABLE 2

A.P.I. Estimates of Proved Reserves—United States
Summary of Committee's Annual Reports Covering Period 1937-1950
(Thousands of Barrels of 42 U. S. Gallons)

	New Oil Found During Year					
Year	Through Revisions of Previous Estimates and Extensions to Known Fields	Through New Pools Discovered During Year	Total Through New Discoveries, Extensions and Revisions	Production During Year	Estimated Proved Reserves as of End of Year	Increase Over Previous Year
1936....	—	—	—	—	13,063,400	—
1937....	2,792,790	928,742	3,721,532	1,277,664	15,507,268	2,443,868
1938....	2,243,571	810,493	3,054,064	1,213,186	17,348,146	1,840,878
1939....	2,058,455	340,667	2,399,122	1,264,256	18,483,012	1,134,866
1940....	1,607,012	286,338	1,893,350	1,351,847	19,024,515	541,503
1941....	1,538,989	429,974	1,968,963	1,404,182	19,589,296	564,781
1942....	1,618,925	260,051	1,878,976	1,385,479	20,082,793	493,497
1943....	1,202,368	282,418	2,484,786	1,503,427	20,064,152	(—)18,641
1944....	1,556,192	511,308	2,067,500	1,678,421	20,453,231	389,079
1945....	1,690,315	419,984	2,110,299	1,736,717	20,826,813	373,582
1946....	2,413,628	244,434	2,658,062†	1,726,348	20,873,560	931,714
1947....	2,019,140	445,430	2,464,570†	1,850,445	21,487,685	614,125
1948....	3,398,726	396,481	3,795,207†	2,002,448	23,280,444	1,792,759
1949....	2,297,428	890,417	3,187,845†	1,818,800	24,649,489	1,369,045
1950....	1,997,769	564,916	2,562,685†	1,943,776	25,268,398	618,909

† Not strictly comparable with years prior to 1946 due to the exclusion of reserves of cycle-plant and lease condensate amounting to 884,967,000 barrels on 12/31/45.

The shortcomings of estimates of reserves based on current data are recognized. In order to give a more correct picture of the history of discoveries and reserves it has now become frequent practice to correct past estimates by applying to the discovery year of each field all revisions and extensions to reserves made subsequent to discovery. This results in fairly accurate estimates of discoveries and reserves for older fields, inasmuch as the bulk of revisions and extensions to estimated reserves of the average field occur within the first few years after discovery.

Analysis of the history of the reserves of young fields shows that on the average an estimate of ultimate recovery made at the end of the discovery year will eventually increase severalfold as the result of subsequent extensions and revisions. The largest revisions are usually made during the first year after discovery; the amount of increase becomes less each year, until after a number of years the volume of reserves in the average field becomes fairly well defined.

Table 4 gives the P.A.W. (Petroleum Administration for War) estimates of discoveries from 1914 through 1944 determined by assigning all revisions and extensions to the year of discovery for each field.

Table 4 presents a relatively accurate history of reserves

TABLE 3

Estimated Proved Reserves of Crude Oil in the United States

(Thousands of Barrels of 42 U. S. Gallons)

	Proved Reserves as of December 31, 1949 (1)	Changes in Proved Reserves Due to Extensions (New Crude Oil) and Revisions During 1950 (2)	Proved Reserves Discovered in New Fields and in New Pools in Old Fields in 1950[*] (3)	Production During 1950 (4)	Proved Reserves as of December 31, 1950 (Columns 1 + 2 + 3 less Column 4) (5)
Alabama........	3,547	2,376	116	643	5,396
Arkansas.......	297,463	69,163	4,284	29,201	341,709
California.......	3,822,751	227,673	10,745	327,607	3,733,562
Colorado........	344,812	15,215	2,590	23,088	339,529
Illinois.........	468,138	150,509	8,582	63,011	564,218
Indiana.........	50,209	7,440	9,969	10,246	57,372
Kansas.........	738,390	73,680	27,698	107,581	732,187
Kentucky.......	56,168	7,676	2,415	10,388	55,871
Louisiana.......	1,909,769	396,285	79,342	200,259	2,185,137
Michigan.......	66,496	26,729	1,409	15,917	78,717
Mississippi......	402,860	15,819	2,900	35,874	385,705
Montana.......	112,393	7,141	240	8,502	111,272
Nebraska.......	1,624	5,368	4,033	1,325	9,700
New Mexico....	592,222	31,065	12,418	43,723	591,982
New York......	62,900	...	...	4,092	58,808
Ohio...........	27,703	2,875	...	3,314	27,264
Oklahoma.......	1,329,918	193,331	37,531	163,867	1,396,913
Pennsylvania....	103,356	15,000	...	11,996	106,360
Texas..........	13,509,732	551,170	338,669	817,929	13,581,642
Utah...........	15,831	7,000	25	1,227	21,629
West Virginia...	37,992	3,500	350	2,800	39,042
Wyoming.......	691,602	188,434	21,600	60,620	841,016
Miscellaneous[†]...	3,613	320	...	566	3,367
Total U.S.......	24,649,489	1,997,769	564,916	1,943,776	25,268,398

[*] Only a limited area is assigned to each new discovery, even though the committee may believe that eventually a much larger area will produce; for, in this report, the concern is only with actually proved reserves.

[†] Under Miscellaneous are included Florida, Missouri, Tennessee and Virginia.

through the year 1935, but the indicated reserves for the later years are subject to important corrections, owing to future revisions and extensions yet to be made to reserves of fields discovered in the more recent years. Average experience indicates that figures reported at the end of 1944 for reserves found in fields discovered in 1936 will ultimately increase by a relatively small percentage; however, the amount of probable correction becomes greater in the more recent years, and for the most recent year amounts to a probable increase to severalfold the original estimate.

Chart I illustrates the difference between a conventional type of estimate of proved reserves, such as prepared by the A.P.I., and reserves estimates of the type in which past revisions and extensions are credited to the discovery year for each field. Over the period from 1922, when a conventional type of reserves estimate was first prepared by the United States Geological Survey, until about 1938, the general trends in proved reserves shown by the two types of estimate are roughly parallel. Beyond 1938 the two types of estimate converge. The conventional type of estimate gives the impression that, on the whole, our reserves have increased steadily throughout the years. On the other hand, the type of estimate in which past revisions are credited to the applicable year of discovery gives the impression that reserves have declined since 1938. This latter impression is not correct. If revisions are to be credited to the year of discovery for each field, then all revisions, both past and probable

TABLE 4

Fundamental Position of Crude Oil Producing Industry—United States*

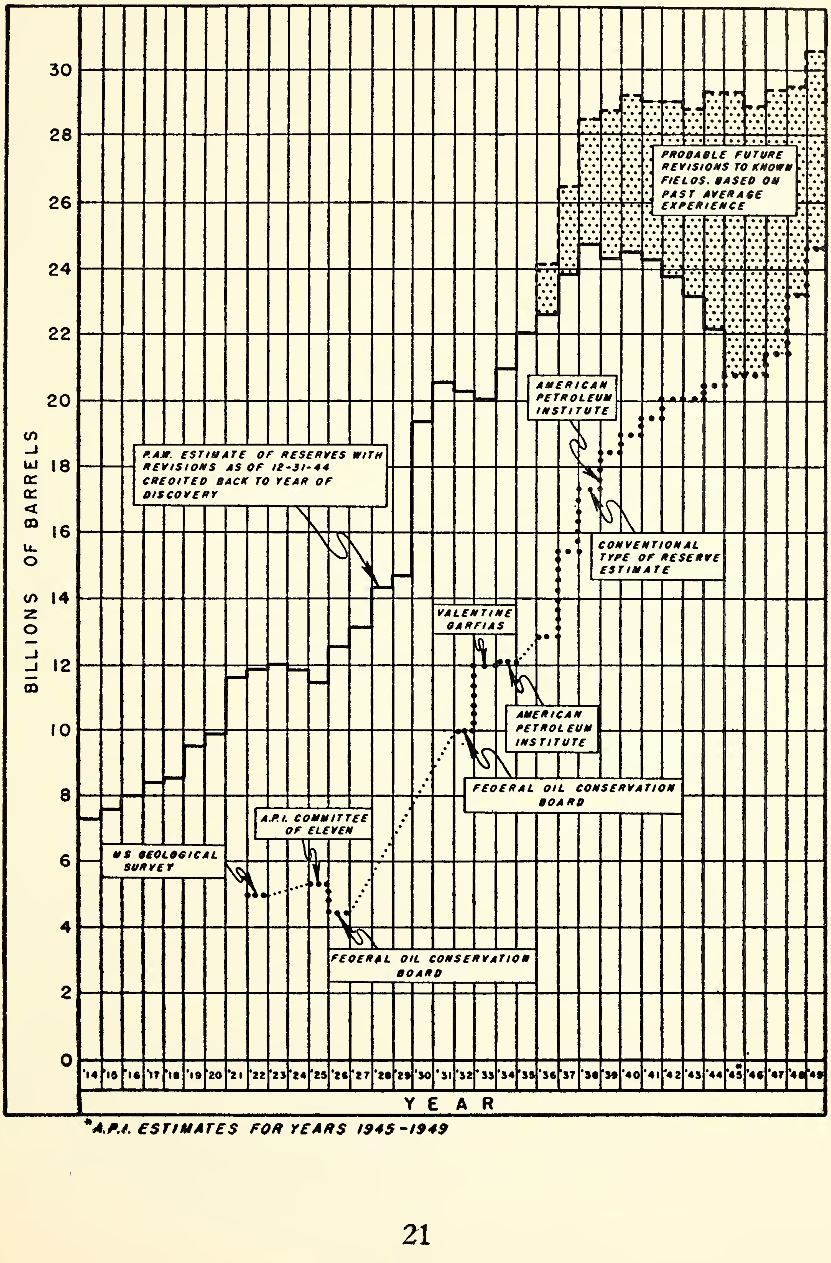
(Millions of Barrels)

Year	Gross Production (Bureau of Mines)	New Reserves Discovered—Gross (P.A.W.)	Ratio Discoveries to Production	Proved Reserves End of Year (P.A.W.)	Ratio Reserves to Production
1914	266	219	.82	7,320	27.52
1915	281	587	2.09	7,626	27.14
1916	300	750	2.50	8,076	26.92
1917	335	684	2.04	8,425	25.15
1918	357	452	1.27	8,520	23.87
1919	378	1,440	3.81	9,582	25.35
1920	443	811	1.83	9,950	22.46
1921	471	2,156	4.58	11,635	24.70
1922	558	913	1.64	11,990	21.49
1923	732	810	1.11	12,068	16.49
1924	714	599	.84	11,953	16.74
1925	763	345	.45	11,535	15.12
1926	772	2,000	2.59	12,673	16.42
1927	900	1,404	1.56	13,267	14.74
1928	902	2,105	2.33	14,470	16.04
1929	1,007	1,357	1.35	14,820	14.72
1930	898	5,482	6.10	19,404	21.61
1931	851	2,080	2.44	20,633	24.25
1932	786	540	.69	20,387	25.94
1933	905	626	.69	20,108	22.22
1934	908	1,880	2.07	21,080	23.22
1935	996	2,115	2.12	22,199	22.29
1936	1,100	1,627	1.48	22,726	20.66
1937	1,279	2,454	1.92	23,901	18.69
1938	1,214	2,115	1.74	24,802	20.43
1939	1,265	818	.65	24,355	19.25
1940	1,353	1,539	1.14	24,531	18.13
1941	1,402	1,269	.91	24,388	17.40
1942	1,387	840	.61	23,836	17.19
1943	1,505	936	.62	23,262	15.46
1944	1,678	659	.39	22,243	13.26

* Quoted from report on the cost of finding, developing and producing crude petroleum submitted to the Office of Price Administration by the National Crude Oil Advisory Committee — February 11, 1946.

CHART I—ANNUAL RECORD OF U. S. RESERVES

Comparing the Conventional Type of Reserve Estimate with Estimates in Which Allowance Is Made for Past and Average Expected Future Extensions and Revisions to Reserves of Known Fields



*A.P.I. ESTIMATES FOR YEARS 1945-1949

future revisions, of all known fields must be added if a true relationship between past and present reserves is to be obtained.

The shaded area of Chart I indicates the order of magnitude of the revisions, as estimated from past experience, that would normally be expected to be made in the future to the estimated proved reserves of present known fields. The inclusion of the anticipated future revisions brings the comparison of past and present reserves into a more proper relationship and indicates that there has not been a decrease in reserves. The chart does indicate, however, that during the period from 1938 to 1949 reserves did not increase at a rapid rate.

Chart II shows the history of the discovery and production of crude oil in the United States, including the cumulative production, the annual and cumulative discoveries, and the ratio of reserves to production for the years 1914 through 1949.

ELEMENTS OF COST OF FINDING AND DEVELOPING OIL RESERVES—UNITED STATES

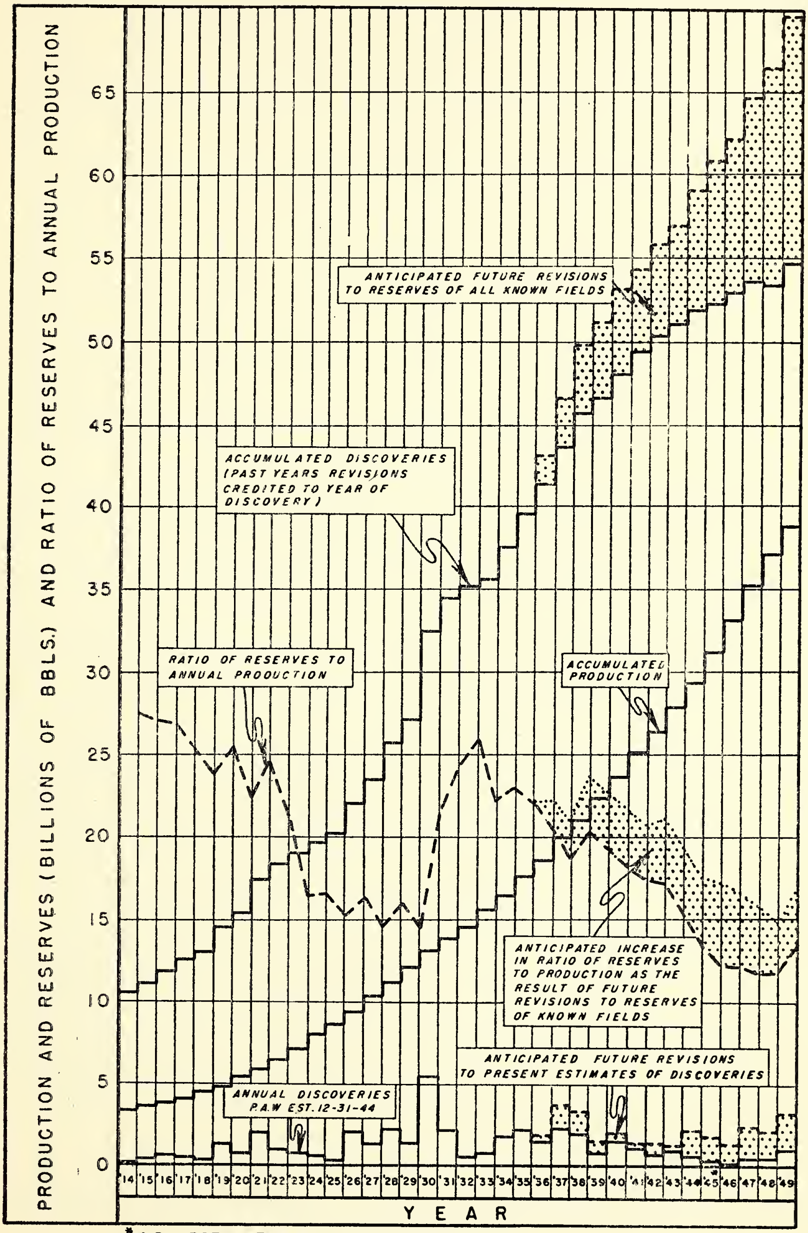
The petroleum industry is accustomed to studying its over-all costs under three subdivisions: "Finding Costs," "Development Costs," and "Operating Costs." Finding costs represent the money spent in finding and acquiring reserves; development costs represent the money spent in drilling wells and building facilities necessary to produce oil and gas; and operating costs represent the cost of producing oil and gas from properties on which they have already been discovered and developed.

Finding Costs include the costs of geological and geophysical exploration, the bonus or purchase price paid for leases, rentals paid on exploratory acreage, and the cost of drilling dry holes. Information is not available industry-wide covering the major elements of finding costs. For this reason it is not possible to arrive at specific figures for the cost of finding oil. It is possible, however, to indicate the general trend in finding costs by comparing the discoveries reported each year by the A.P.I. with various measures of exploration activity.

Table 5 gives data on exploratory drilling, geophysical activity, and the estimated volume of new discoveries for the years 1936-1949. The drilling and geophysical data show that the rate of exploration activity has increased steadily during this period. The amount of new oil discovered each year has fluctuated over a rather

CHART II—PRODUCTION AND DISCOVERY HISTORY, UNITED STATES

Discoveries Based on Crediting to Year of Discovery All Past and Average Expected Future Revisions to Reserves of Known Fields



*A.P.I. ESTIMATES FOR YEARS 1945-1949

TABLE 5

Exploratory Activity and Discoveries—United States

Year	Total Dry Holes Field and Wildcat Wells[1]	Exploratory Statistics Seventeen Major Producing States[2]			Geophysical Activity[3] Number of Crews		Reported Discoveries Millions of Barrels[4]
		Dry Exploratory Wells					
		Number	Average Depth Feet	New Field Discovery Wells	Seismograph	Gravity Meter	
1936	5,695		Not available		175	35	Not available
1937	6,730		Not available		210	40	929
1938	6,133	2,264	3,225	226	205	40	810
1939	6,670	2,396	3,176	175	185	40	341
1940	6,770	2,618	3,298	238	190	45	286
Annual Average	6,399	2,426	3,233	219	195	40	591
1941	6,984	2,716	3,493	281	190	55	430
1942	5,684	2,690	3,678	263	220	60	260
1943	5,952	3,144	3,892	288	250	70	282
1944	6,751	3,672	4,147	330	300	120	511
1945	7,231	4,178	4,022	335	340	155	420
Annual Average	6,520	3,284	3,846	300	260	90	380
1946	8,503	4,419	3,890	313	370	130	244
1947	9,546	5,138	3,935	378	420	120	445
1948	11,512	6,164	3,941	471	470	115	396
1949	12,597	6,996	3,668	480	480	90	890
Annual Average	10,540	5,704	3,858	410	435	115	494

[1] Figures from World Oil.

[2] Dr. Frederic H. Lahee—Sun Oil Company. Figures cover California, New Mexico, Texas, Oklahoma, Kansas, Arkansas, Louisiana, Mississippi, Illinois, Indiana, Michigan, Colorado, Wyoming, Montana, Nebraska, Kentucky, and Alabama.

[3] 1936-1939 compiled by Standard Oil Co. (N. J.); 1940-1949 adapted from data of E. A. Eckhardt.

[4] A.P.I. estimates of reserves added through new pools discovered during year. (These reported discoveries are not corrected for revisions made in subsequent years.)

wide range, and the average trend is somewhat obscure. Although the data on new oil discoveries do not include estimated future revisions, and are therefore only indicative rather than a true measure of the amount of new oil actually discovered each year, the data suggest that the rate of discovery has not increased, on the average, as rapidly as exploration activity. If this is a true trend it indicates that the average cost of finding new reserves is increasing. The finding cost is also increasing as a result of the gradually increasing average depth of exploratory wells.

The tendency of costs to rise is held in check primarily through technologic improvements and increased efficiency. Unless such improvements of conventional exploration methods can in the future overcome the increasing difficulties of finding and drilling for new oil, or unless more effective exploration methods than those now available are developed, future costs of finding new oil may be expected to follow an upward trend.

Development Costs include the cost of drilling wells, together with the cost of facilities necessary for the production of oil and gas. The only industry-wide data available that give an indication of the trend in development costs are data on the number of wells completed, the average depth of productive wells, and the average development cost for each foot drilled. Inasmuch as drilling is the major cost in normal oil-field development, the trend in the cost of drilling indicates the trend in over-all development costs. Table 6 gives data on well completions and costs for the period 1936-1949. These data indicate an upward trend in development costs.

TABLE 6

Well Completion Data and Estimated Development Costs—United States

Year	Productive Oil and Gas Wells Completed[1]	Average Depth Feet[1]	Average Cost per Foot Drilled[2]
1936	20,755	2,861	$ 8.77
1937	24,981	2,974	8.41
1938	20,457	3,095	8.58
1939	19,630	3,042	7.63
1940	21,248	3,073	Not available
Annual Average, 1936—1939	21,414	3,015	$ 8.34
1941	22,054	3,158	$ 7.55
1942	12,922	3,269	8.96
1943	11,156	3,186	11.11
1944	15,456	3,467	12.79
1945	16,371	3,679	Not available
Annual Average, 1941—1944	15,591	3,351	$10.10
1946	19,472	3,514	Not available†
1947	21,287	3,569	
1948	25,147	3,564	
1949	24,715	3,717	
Annual Average	22,655	3,591	

[1] Figures from Oil Weekly, 1936-1940 average depth all completions; 1941-1945 average depth productive wells only.

[2] From Report on the Cost of Finding, Developing, and Producing Crude Petroleum submitted to the Office of Price Administration by the National Crude Oil Industry Advisory Committee, February 11, 1946.

† Private estimates indicate the average cost per foot drilled increased 42% during 1945-1949.

The average depth of productive wells has increased steadily over the years, and in recent years the average cost of each foot drilled has increased sharply. The increasing cost of development is a hindrance to the further expansion of petroleum production. Reduction in development cost, like in finding cost, is dependent on technologic progress and increased efficiency. Increasing costs per well may be offset by the more efficient use of wells. Avoidance of unnecessary drilling, development of each reservoir as a single geologic unit with the minimum number of wells required for efficient recovery, and the use of more efficient recovery methods offer the best prospects for future reduction of development costs.

CRUDE OIL PRODUCTION AND RESERVES—WORLD-WIDE

There has been a tremendous growth in world consumption of petroleum in the more than 90 years since the first oil well was completed in the United States. During this period petroleum has played an important part in the industrial and economic progress of the world. Since its early use primarily as an illuminant, petroleum has helped supply the fuel and lubricants necessary for the industrial and motor era of the 20th century.

Estimated Past and Present Rates of Consumption

The drilling of the first oil well in this country in 1859 stimulated activity in other areas, and world crude oil production increased from an average of less than 500 barrels daily in the 1857-1860 period to more than 400,000 barrels a day at the turn of the century. Complete records are not available on the actual amounts consumed in the early years, but in 1900 the United States domestic requirements for oil were about 100,000 barrels daily. The remainder of the world at that time was consuming 300,000 barrels daily.

As a result of the use of fuel oil for generating power, and the development of the internal combustion engine, with its demand for gasoline, consumption of crude oil continued to expand. At the outbreak of World War I the world demand had risen to 1,000,000 barrels a day, more than double the 1900 rate. Consumption of oil in the United States in 1914 accounted for more than half of the world total.

There was a sharp increase in demand for oil brought about by developments during the first World War. World-wide consumption in 1918 was 50% greater than the 1914 rate, with an average of 1,500,000 barrels daily being consumed. The greater part of this increase was in the United States, as conditions abroad reflected to a greater degree the adverse effects of the war. Domestic demand in this country in 1918 averaged almost 1,000,000 barrels a day.

The industrial expansion between the end of the first World War and the beginning of World War II; the tremendously increased use of passenger automobiles, trucks, and busses; and the increased heating of homes with automatic oil burners were all reflected in the growth of oil consumption during the 1919-1938 period. Except for two years, 1931 and 1932, during the depression, there was a steady increase each year in world consumption of oil. In 1938 world requirements were 5,600,000 barrels daily, or nearly four times the 1918 rate. The domestic demand in the United States had increased to 3,100,000 barrels a day, and foreign demand had increased to 2,500,000 barrels daily.

The second World War created a record demand for oil. In 1945, the final year of the conflict, the world demand was estimated at about 7,500,000 barrels a day. The demand would have been greater had supplies been available, for during the war period it was necessary to restrict unessential uses in order to provide the amounts required by the military.

Despite post-war restriction on consumption in a number of areas, world demand for petroleum products continued to climb to record levels each succeeding year.

Estimates of world demand for oil from 1900 through 1949 at five-year intervals are shown in Table 7.

A continuation of technologic advances in discovering, producing, refining, and utilizing petroleum should lead to further increases in consumption for many years to come.

The past record of oil consumption in the United States shows an average increase during the last thirty years at the rate of slightly over 5% a year. This rate of increase of consumption cannot, of course, be maintained indefinitely, but all available data indicate that substantial further increases will occur before any tendency toward leveling off will materialize.

TABLE 7

Estimated World Demand for Oil

(Barrels of 42 Gallons, Daily)

Year	World	United States	Foreign Countries
1900	400,000	100,000	300,000
1905	573,000	270,000	303,000
1910	874,000	448,000	426,000
1915	1,074,000	553,000	521,000
1920	1,863,000	1,245,000	618,000
1925	2,930,000	1,992,000	938,000
1930	4,107,000	2,536,000	1,571,000
1935	4,676,000	2,695,000	1,981,000
1940	6,103,000	3,625,000	2,478,000
1945	7,516,000	4,857,000	2,659,000
1949	9,744,000	5,792,000	3,952,000

Distribution of Present Production and Estimated Proved Reserves

The total world production of crude oil from the beginning of the industry through the year 1949 was approximately 61 billion barrels, of which 39 billion barrels or 64% was produced by the United States and 22 billion barrels or 36% was produced by foreign countries.

During the year 1949 total world production amounted to 3,400,000,000 barrels, or an average rate of 9,320,000 barrels daily. At the beginning of the year 1950 estimated world-wide proved reserves of oil were estimated at 117 billion barrels. Foreign countries produced 4,278,000 barrels daily in 1949 and contained estimated proved reserves of 92 billion barrels, as compared to production of 5,042,000 barrels daily and estimated proved reserves of 25 billion barrels in the United States. Estimated world-wide proved reserves of oil as of January 1, 1950, by major producing regions are compared with the 1949 production in Table 8.

Table 8 indicates the high rate at which the United States is producing its proved reserves as compared with the rest of the

TABLE 8

Production and Estimated Proved Reserves by Major Oil-Producing Regions of World[*]

	1949 Production		Proved Reserves 1/1/50	
Western Hemisphere	1,000's of Barrels Daily	% Total World	Millions of Barrels	% Total World
United States	5,042	54.1	24,649	21.0
Balance North America	224	2.4	2,198	1.9
N. W. South America[†]	1,450	15.5	9,370	8.0
Balance South America	120	1.3	594	0.5
Total	6,836	73.3	36,811	31.4
Eastern Hemisphere				
Europe and Russia[‡]	835	9.0	6,826	5.8
Near and Middle East[+]	1,446	15.5	71,632	61.0
Oceania	190	2.0	1,938	1.7
Balance Eastern Hemisphere	13	0.2	137	0.1
Total	2,484	26.7	80,533	68.6
Total World	9,320	100.0	117,344	100.0

[*] Tabulation compiled by Standard Oil Co. (N.J.)

[†] Venezuela, Colombia, Ecuador, Peru.

[‡] Estimates for Russia are highly speculative, as no reliable information is available.

[+] Includes Egypt.

world. It also shows the low rate at which the huge resources of the Near and Middle East are being withdrawn. The United States, with only 21% of the world's estimated proved reserves, produced 54% of the world production during 1949, whereas the Near and Middle East, with 61% of the world's estimated proved reserves, produced only 15.5% of the world production. In other words, the United States produced at three and one-half times the rate of the Near and Middle East even though it has only about one-third the proved reserves of that area. The relatively large production in the United States in comparison with the rest of the world is a direct reflection of its much greater industrial development.

Part Two . . . NATURAL GAS RESOURCES

CUMULATIVE GAS PRODUCTION AND ESTIMATED RESERVES—UNITED STATES

There are no comprehensive statistics available on the total production of natural gas in the United States covering the whole period from the beginning of the industry. However, from the rather complete data for recent years, and from the close parallel between the growth of production of natural gas and that of oil, it is possible to arrive at reasonable estimates of the history of natural gas production.

The earliest estimate of natural gas reserves in the United States was apparently made by E. W. Shaw in 1919. Since 1945, estimates of the proved recoverable reserves of natural gas have been made annually by the Committee on Natural Gas Reserves of the American Gas Association.

Production

During the early days of the petroleum industry much of the gas produced with oil was blown to the atmosphere, and many years passed before methods were devised for measuring large movements of gas through a pipe line. In 1906 the United States Geological Survey made a canvass of the gas industry and attempted to obtain comprehensive data on the volume of natural gas produced and used by consumers. That survey provided statistics by states of the volume of production and consumption of natural gas, the number of consumers, and the value at points of consumption. Since that time, annual surveys of natural gas production and use have been made by either the United States Geological Survey or the United States Bureau of Mines.

The growth of production of natural gas in the United States since 1900 is reflected in Chart III, which shows the annual marketed production. This chart is based on data published by the United States Bureau of Mines for 1906 through 1949. Figures for years prior to 1906 are estimates based on other data published by the Bureau on the fuel value of coal displaced by gas. Shown also in Chart III, for comparison, is the annual consumption of liquid fuels (principally from crude oil) in the United States. The close similarity in growth of the consumption of natural gas and oil is readily apparent.

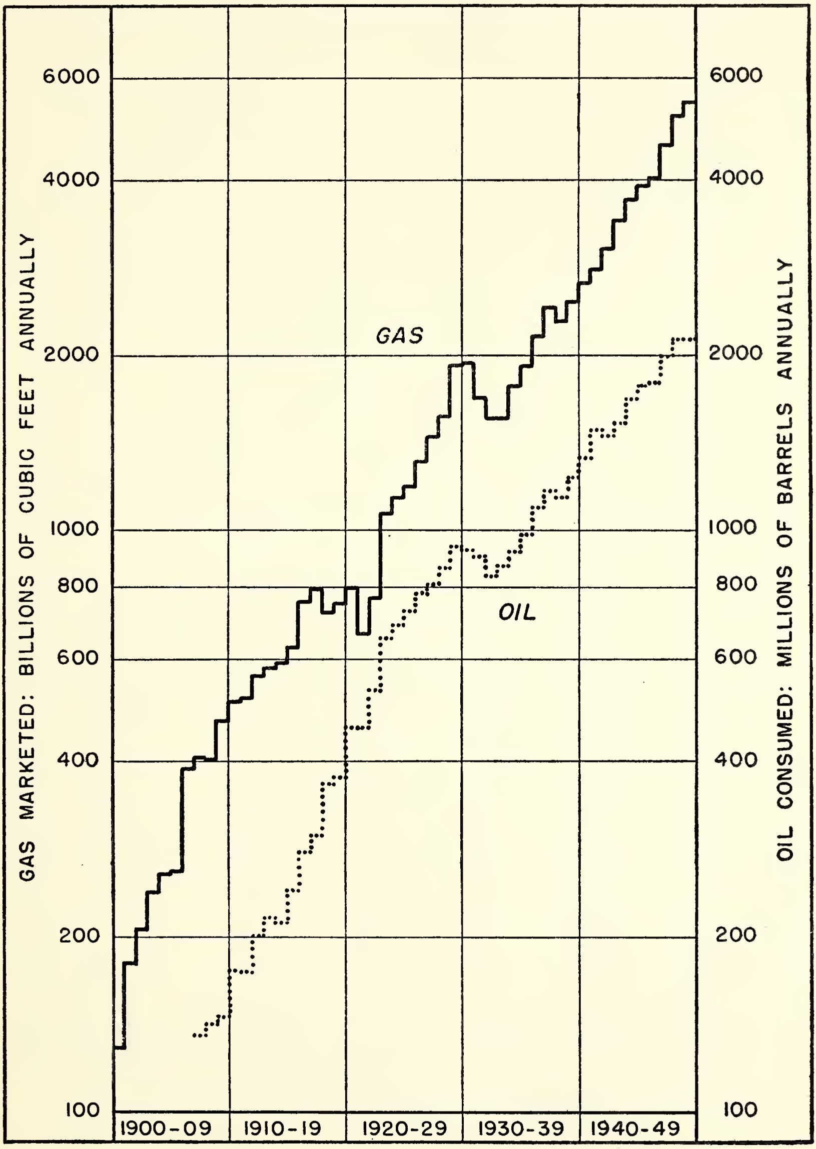
It should be noted that the scales employed in Chart III are chosen to emphasize the parallel growth of consumption of oil and gas rather than their relative absolute importance in terms of fuel value. As is shown in Chart V, the total energy consumed as oil substantially exceeds that consumed as natural gas.

Although the total percentage increase in natural gas marketed and oil consumed has been approximately the same since 1910, it is significant that during the past few years the volume of marketed gas has accelerated annually at a faster rate than the rate of increase of the demand for oil. Marketed production of natural gas in 1949 was 30% higher than the volume for 1946. Over the same three-year period the consumption of oil rose only 18%.

The rapid acceleration in marketed production of natural gas has resulted in large part from the rapidly increasing interstate transportation through new pipe lines built or converted for transportation of natural gas since the war. Over 90% of the increase in marketed production of natural gas during 1949 over 1948 was accounted for by increased interstate movements. Because of the rather large number of interstate pipe lines now under construction or planned for the near future it is to be expected that the volume of marketed production of natural gas will continue to increase at a rapid rate through at least the next few years.

The relation of marketed production of natural gas to the estimated total natural gas production, and the sources of the produced

CHART III—NATURAL GAS MARKETED AND OIL CONSUMED, UNITED STATES



gas, as estimated by the United States Bureau of Mines, are shown in Table 9 for the year 1949.

It will be noted from the tabulation that approximately 66% of the total production of natural gas during 1949 was from gas wells and 34% from oil wells, and that four states, Texas, Louisiana, California, and Oklahoma, accounted for over 80% of the total.

It may be noted, also, in this tabulation that approximately 11% of the total produced natural gas is listed as vented and wasted. This wasted gas is preponderantly gas produced with oil from oil wells, commonly known as casinghead gas. As will be shown in later chapters dealing with the recovery of petroleum, some natural gas is almost always associated with oil in underground reservoirs, and

TABLE 9

Gross Production and Disposition of Natural Gas in the United States, by States, in 1949, in Millions of Cubic Feet

	Estimated Production[1]			Estimated Disposition		
State	From Gas Wells	From Oil Wells	Total	Marketed Production[2]	Repressuring	Vented and Wasted[3]
Arkansas.....	37,500	30,870	68,370	47,788	15,431	5,151
California.....	217,000	518,800	735,800	550,903	173,954	10,943
Colorado......	6,500	7,750	14,250	8,490	370	5,390
Illinois.......	350	37,500	37,850	12,391	3,566	21,893
Indiana.......	250	1,900	2,150	334	927	889
Kansas.......	237,800	86,600	324,400	294,078	3,339	26,983
Kentucky.....	46,700	9,350	56,050	51,851	1,286	2,913
Louisiana.....	785,250	240,250	1,025,500	732,845	185,533	107,122
Michigan.....	14,350	6,600	20,950	14,753	413	5,784
Mississippi....	74,100	38,000	112,100	68,062	38,603	5,435
Montana.....	33,100	3,750	36,850	35,291	183	1,376
New Mexico..	49,920	191,700	241,620	204,961	7,109	29,550
New York....	3,600	170	3,770	3,693	72	5
Ohio.........	47,400	1,700	49,100	46,512	2,087	501
Oklahoma.....	373,200	258,000	631,200	435,262	26,920	169,018
Pennsylvania..	81,500	3,500	85,000	84,739	170	91
Texas........	2,740,000	1,082,000	3,822,000	2,588,921	798,211	434,868
Utah.........	6,150	210	6,360	6,126	—	234
West Virginia.	178,300	7,000	185,300	181,176	1,633	2,491
Wyoming.....	52,450	35,000	87,450	50,815	13,398	23,237
Other States[4]..	706	49	755	745	—	10
Total 1949....	4,988,326	2,560,699	7,546,825	5,419,736	1,273,205	853,884
Total 1948....	4,588,547	2,590,230	7,178,777	5,148,020	1,220,579	810,178

[1] Marketed production plus quantities used in repressuring, vented and wasted.

[2] Includes gas utilized, stored and lost in transmission.

[3] Includes gas (mostly residue) blown to the air, but does not include direct waste on producing properties, except where data are available.

[4] Florida, Missouri, North Dakota, South Dakota, Tennessee, and Virginia.

it has certain functions to perform in the recovery of oil. Its production along with crude oil is unavoidable in the oil-production process. In the past, much of the gas that was produced with oil was wasted, largely because many oil fields were located in regions having no available market or use for the gas, or because the price of gas at the well did not justify the expense of gathering and preparing the casinghead gas for market. That situation has changed rapidly since the war, partly because expanded markets and better prices have removed to a great degree the cause of waste of the gas, and partly because of greater efforts to conserve the gas through injection into underground reservoirs, either for storage or to effect additional oil recovery. Waste of casinghead gas is fast disappearing except in isolated localities where the small volume of available gas or its remoteness from an outlet still make its marketing or other disposition impractical.

NATURAL GAS RESERVES

The estimated proved recoverable reserves of natural gas in the United States as of Dec. 31, 1950, as reported by the Committee on Natural Gas Reserves of the American Gas Association, totaled approximately 186 trillion cubic feet. Details of the estimate by states are presented in Table 10.

The estimated proved reserves of natural gas as presented include the gas in both the drilled and certain undrilled portions of the fields. The various undeveloped areas considered to have proved reserves are those so located with respect to field geology and structure that production therefrom is practically assured. Recoverable reserves of natural gas are the reserves estimated to be producible under existing operating practices. The recovery factors or abandonment pressures used differ with the characteristics of each field and the economics of each region.

Particularly of interest in connection with these estimates is the distribution of the reserves as to the type of occurrence. Approximately 70% of the reserves is classed as non-associated gas, i.e., gas that is not in contact with oil in the reservoir. Some 15% is classed as associated gas, which is gas in immediate contact with oil in the reservoir, and 14% is classed as gas in solution in oil.

The tremendous concentration of the estimated proved reserves of natural gas in the southwestern part of the United States should

TABLE 10

Estimated Proved Recoverable Reserves of Natural Gas in the United States

(Millions of Cubic Feet—14.65 psia, at 60 deg F)

		Changes in Reserves during 1950				Reserves as of December 31, 1950[2]				
	Reserves[2] as of Dec. 31, 1949 (1)	Extensions and Revisions[2] (2)	Discoveries of New Fields and New Pools in Old Fields[2] (3)	Net Change in Underground Storage[3] (4)	Net Production[4] (5)	Total (Columns 7 + 8 + 9 + 10, also Columns 1 + 2 + 3 + 4 less Column 5) (6)	Non-Associated[5] (7)	Associated[6] (8)	Dissolved[7] (9)	Underground Storage[8] (10)
Arkansas......	874,190	65,072	23,129	540	55,338	907,593	450,935	157,869	296,789	2,000
California[9].....	9,991,635	225,279	71,840	4,028	532,396	9,760,386	2,702,746	2,286,788	4,751,693	19,159
Colorado......	1,227,095	(—)134,453	41,426	0	18,595	1,115,473	474,704	33,528	607,241	0
Illinois........	233,192	26,774	5,700	0	35,773	229,893	5,643	15,000	209,250	0
Indiana.......	25,200	6,720	4,920	750	6,400	31,190	4,000	5,000	21,440	750
Kansas........	14,089,560	64,729	30,360	153	393,968	13,790,834	13,381,105	152,189	228,239	29,301
Kentucky.....	1,349,397	49,294	8,200	(—)908	75,400	1,330,583	1,254,997	0	64,000	11,586
Louisiana[9].....	26,687,811	2,010,120	751,133	0	915,798	28,533,266	22,477,745	4,162,574	1,892,947	0
Michigan......	214,911	(—) 14,820	2,741	10,528	18,286	195,074	121,867	0	40,906	32,301
Mississippi....	2,528,969	130,470	5,030	0	145,263	2,519,206	1,772,969	410,436	335,801	0
Montana......	803,471	34,951	0	2,402	43,463	797,361	722,647	44,799	25,421	4,494
Nebraska......	8,063	9,028	28,073	0	1,058	44,106	14,886	21,213	8,007	0
New Mexico...	6,241,003	866,625	124,404	6,883	248,245	6,990,670	3,978,271	2,098,103	896,210	18,086
New York.....	66,685	200	0	1,094	3,200	64,779	53,375	0	595	10,809
Ohio..........	652,571	38,751	7,900	6,840	47,200	658,862	550,548	0	34,500	73,814
Oklahoma.....	11,625,979	486,813	121,163	8,250	607,918	11,634,287	7,509,209	1,011,782	3,088,927	24,369
Pennsylvania..	621,680	31,000	50,000	(—)509	75,000	627,171	528,569	0	40,750	57,852
Texas[9]........	99,170,403	5,055,893	1,557,691	490	3,380,400	102,404,077	71,529,387	17,646,015	13,228,185	490
Utah..........	65,577	8,196	15,112	0	4,133	84,752	76,331	0	8,421	0
West Virginia..	1,715,233	105,152	21,750	13,540	205,000	1,650,675	1,513,009	0	81,500	56,166
Wyoming......	2,173,677	96,631	2,749	220	78,288	2,194,989	1,481,156	128,456	584,864	513
Miscellaneous[1].	15,042	9,956	4,030	0	1,556	27,472	24,356	0	3,116	0
Total.....	180,381,344	9,172,381	2,877,351	54,301	6,892,678	185,592,699	130,628,455	28,173,752	26,448,802	341,690

[1] Includes Alabama, Florida, Maryland, Missouri, North Dakota and Virginia.

[2] Excludes gas loss due to natural gas liquids recovery.

[3] The net difference between gas stored in and gas withdrawn from underground storage reservoirs.

[4] Net production equals gross withdrawals less gas injected into underground reservoirs; changes in underground storage are excluded. December production estimated occasionally.

[5] Non-associated gas is free gas not in contact with crude oil in the reservoirs.

[6] Associated gas is free gas in contact with crude oil in the reservoirs.

[7] Dissolved gas is gas in solution with crude oil in the reservoirs.

[8] Gas held in underground reservoirs for storage purposes only.

[9] Includes off-shore reserves.

also be noted. The states of Kansas, Louisiana, Oklahoma, and Texas are credited with approximately 84% of the presently proved reserves, and the state of Texas alone accounts for 55% of the total.

The growth of the proved reserves of natural gas in the United States is shown by Chart IV, which is based on published estimates from various sources, as listed in Table 11.

It is interesting that the trend shown in Chart IV has been one of a consistent increase in reserves, the indicated increase being over tenfold in the thirty-year period from 1920 to 1950. Estimated proved reserves of natural gas have increased at a substantially faster rate than have the estimated proved reserves of oil, the latter having increased only fivefold over the same thirty-year period.

In terms of fuel value, 6,000 cubic feet of natural gas is approximately equivalent to one barrel of oil. The present estimated proved reserves of 186 trillion cubic feet of natural gas are therefore equivalent in fuel value to approximately 31 billion barrels of oil, a quantity some 20% greater than the present estimated proved crude

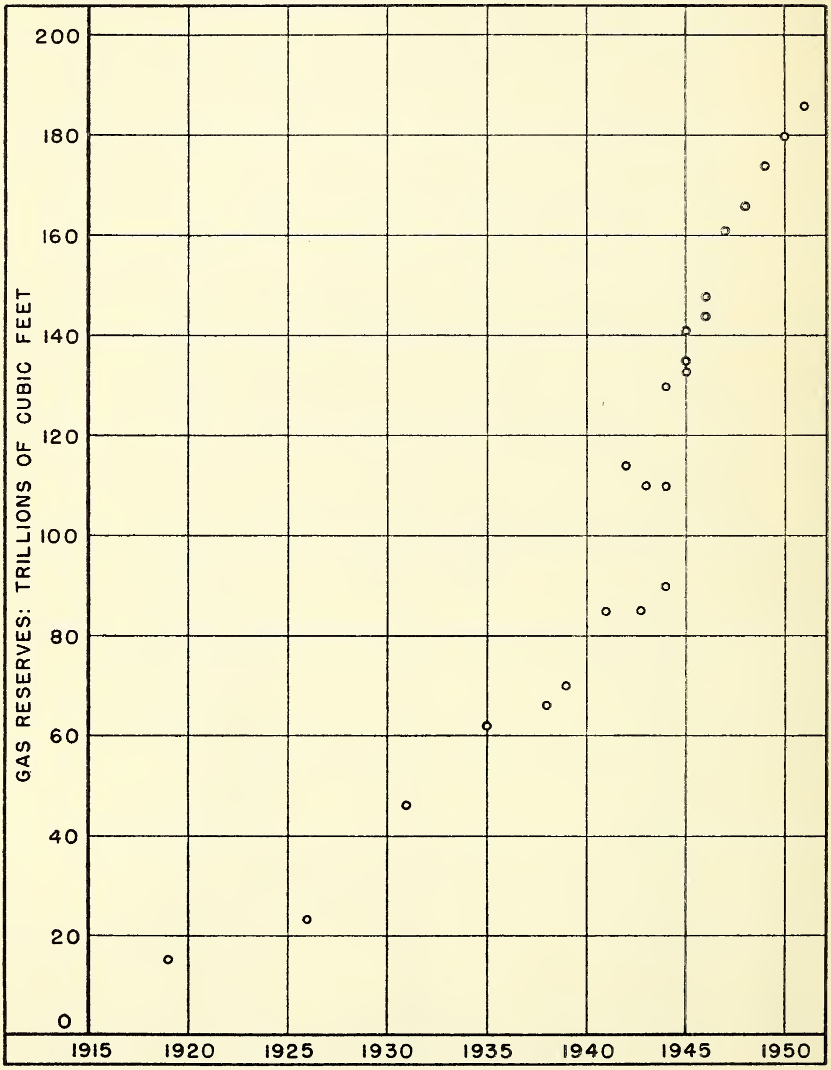
TABLE 11

Summary of Estimates of Natural Gas Reserves, 1919-1950

Year (Jan. 1)	Estimated Reserves Trillions of Cubic Feet	Estimate By
1919	15	E. W. Shaw
1926	23	Not identified
1931	46	Earle P. Hindes
1935	62	Ralph E. Davis
1938	66	Ralph E. Davis
1939	70	Lyon F. Terry
1941	85	Ralph E. Davis
1942	114	P.A.W.
1942*	85	Ralph E. Davis
1943	110	P.A.W.
1944	90	Ralph E. Davis
1944	110	P. A. W.
1944	130	Alec M. Crowell
1945	133	P. A. W.
1945	135	Alec M. Crowell
1945	141	DeGolyer & MacNaughton
1946	144	DeGolyer & MacNaughton
1946	148	American Gas Association
1947	161	American Gas Association
1948	166	American Gas Association
1949	174	American Gas Association
1950	180	American Gas Association
1951	186	American Gas Association

* October 1, 1942.

Chart IV—ESTIMATES OF PROVED RESERVES OF NATURAL GAS, UNITED STATES



oil reserves and slightly exceeding the total estimated proved reserves of all hydrocarbon liquids in the United States.

Natural Gas Liquids

Petroleum in an underground reservoir is a complex mixture of hydrocarbons covering the complete range from methane, the chief constituent of natural gas, through hydrocarbons of intermediate volatility, to those that under ordinary conditions are stable liquids or even solids. The manner of occurrence of the materials and the effects on recovery techniques are discussed elsewhere. From the standpoint of reserves, however, it should be noted that the intermediate hydrocarbons are found in both natural gas and oil and may be extracted or isolated from either in various forms, such as liquefied petroleum gas, commonly known as LPG or bottled gas, and natural gasoline. Such materials are extractable from natural gas produced from a reservoir either in the form of free gas or as dissolved gas liberated from oil in the process of production. In addition, many deep, high pressure gas reservoirs contain in the vapor state, as part of the gas, liquefiable heavier hydrocarbons that may be separated in the form of a liquid commonly known as condensate. All of these materials recoverable as liquids are a part of the petroleum supply. Together they constitute a significant supplement to crude oil.

During the past several years estimates of the proved reserves of these natural gas liquids have been made jointly by committees of the American Gas Association and the American Petroleum Institute. Their estimates of these reserves as of December 31, 1950, are summarized in Table 12. They totaled at that time 4,268,000,000 barrels or over 14% of the total estimated liquid hydrocarbon reserves. The indicated reserves of these materials are those estimated to be contained in recoverable gas reserves and to be extractable by methods now in use.

RECENT HISTORY OF TOTAL U. S. PETROLEUM PRODUCTION

The annual production of crude oil, natural gas liquids, and natural gas, as compiled by the reserves committees of the American Petroleum Institute and the American Gas Association for the period 1946-1950, are recapitulated in Table 13. This tabulation permits a comparison of the recent trend of production of each.

It is evident from this tabulation that production of both natural

TABLE 12

*Estimated Proved Recoverable Reserves of Natural Gas Liquids in the United States**

(Thousands of Barrels of 42 U. S. Gallons)

		Changes in Reserves during 1950			Reserves as of December 31, 1950			
	Reserves as of Dec. 31, 1949 (1)	Extensions and Revisions (2)	Discoveries of New Fields and New Pools in Old Fields (3)	Net Production (4)	Total (Columns 6 + 7 + 8, also Columns 1 + 2 + 3 Less Column 4) (5)	Non-Associated (6)	Associated (7)	Dissolved (8)
Arkansas	55,642	745	230	3,679	52,938	31,997	7,586	13,355
California[3]	320,275	71,079	250	28,217	363,387	0	137,492	225,895
Colorado	24,190	(—)10,837	0	432	12,921	873	0	12,048
Illinois	26,666	3,003	28	3,438	26,259	28	75	26,156
Indiana	126	34	24	32	152	20	25	107
Kansas	106,405	60,578	341	3,746	163,578	159,702	1,594	2,282
Kentucky	13,245	308	154	1,780	11,927	11,927[2]	0	0
Louisiana[3]	596,422	56,492	18,992	28,394	643,512	498,484	97,437	47,591
Michigan	1,203	(—) 75	14	124	1,018	609	0	409
Mississippi	56,407	2,040	100	2,650	55,897	26,558	23,295	6,044
Montana	3,710	81	0	244	3,547	3,547	0	0
Nebraska	37	65	140	7	235	74	107	54
New Mexico	85,719	11,773	1,370	4,965	93,897	30,876	33,211	29,810
Ohio	1,670	108	12	102	1,688	1,688[2]	0	0
Oklahoma	234,030	61,897	4,922	20,946	279,903	121,708	24,868	133,327
Pennsylvania	2,643	135	68	247	2,599	2,599[2]	0	0
Texas[3]	2,143,711	443,190	31,326	122,188	2,496,039	1,434,654	359,067	702,318
Utah	208	(—) 9	0	5	194	194	0	0
West Virginia	12,831	634	212	4,701	8,976	8,976[2]	0	0
Wyoming	43,863	6,636	0	1,512	48,987	37,675	6,390	4,922
Miscellaneous[1]	9	2	0	2	9	0	0	9
Total	3,729,012	707,879	58,183	227,411	4,267,663	2,372,189	691,147	1,204,327

* Includes condensate, natural gasoline and liquefied petroleum gas.

[1] Includes Alabama and Florida.

[2] Not allocated by types but occurring principally in the column shown.

[3] Includes off-shore reserves.

gas and natural gas liquids has increased at a much greater percentage rate during the immediate past than has the production of crude oil. The most rapid growth is shown by the natural gas liquids, the production of which increased 76% from 1946 to 1950. The great increase in production of natural gas liquids during this period reflects the construction of a large number of plants for the recovery of natural gasoline in connection with projects for the conservation of casinghead gas, increased gas cycling in condensate fields, and increased efficiency of extraction of propane and butanes to supply an expanding market.

TABLE 13

Annual Production Petroleum Liquids and Natural Gas, 1946-1950

	Net Production During Year		
	Millions of Barrels		Billions of Cubic Feet
Year	Crude Oil	Natural Gas Liquids	Natural Gas
1946	1,726	129	4,943
1947	1,850	161	5,630
1948	2,002	184	6,008
1949	1,819	199	6,245
1950	1,944	227	6,893

OUTLOOK FOR FUTURE DISCOVERIES AND PROSPECTS FOR UPWARD REVISIONS IN PRESENTLY ACCEPTED RESERVES ESTIMATES— UNITED STATES

The various factors that affect the production, use, and also the future outlook for crude oil apply in similar fashion to natural gas. The situation for natural gas, however, is further complicated by the physical form of the commodity, which makes it difficult to harness, difficult to store against possible future demands, and difficult to transport to potential markets. It is also complicated by the fact that a large amount of the natural gas produced with oil is frequently utilized in the field in connection with the oil-producing operations, in part as lease fuel, and in part for return to the producing formations as a means of increasing the oil recovery. In such instances use of the gas for any other purpose is usually considered secondary to its use in the recovery of oil. Furthermore, since gas and oil are both potential raw materials for the same end products, the two materials are closely related and must be so considered in connection with any questions on reserves, production, and use.

The present reserves or, more correctly speaking, the inventories of natural gas, have been the subject of continuing studies largely because of the need for such information in connection with problems of justifying long-term investments in pipe lines and, more recently, in gas-cycling plants. The estimates are influenced in great measure by such things as immediate market prospects, demand, and prices. As long as adequate supplies are in sight there is little incentive to prove the existence of supplies that will not be required for years in the future. Undoubtedly, if the incentive existed to ascertain the true volume of the presently known recoverable reserves of natural gas the result would indicate a total considerably in excess of the accepted figure of 186 trillion cubic feet.

It is noteworthy that in those areas where natural gas has commanded a high price, such as in the Appalachian area, exploration for and development of reserves of natural gas have been much more intense than in other areas. The lack of market outlets commensurate with the total available supply, and the resultant very low price of gas at the well have been deterrents to the development of natural gas fields in the southwestern area, in which, as has been shown, 84% of the present known reserves of natural gas are located. Undoubtedly, the reserves of natural gas in the Southwest can be tremendously increased through both new discoveries and more complete development whenever the demand and the correspondingly higher prices will be sufficient to justify more intensive exploration efforts.

The present outlook for the development of natural gas reserves in new areas heretofore unexplored is complicated by the many factors that influence exploration programs. Inventories of natural gas at present are more than ample to take care of existing pipe-line outlets and those under construction. The known reserves at the present ratio of withdrawal would supply the market for many years to come. However, other major pipe-line projects are currently under construction, and such additions should result in a continuation of the increased annual rate of consumption observed during the past few years. The higher prices that should result from such increased demand should provide a new incentive for intensive exploration in both old and new potential gas-producing areas, leading ultimately to new discoveries that may greatly exceed past discoveries.

INTERRELATION AND INTERCONVERSION OF GAS TO OIL AND ITS SIGNIFICANCE

From the data of Charts III and IV, which constitute a record of the accomplishments to date, it is only reasonable to assume that extensive additions to reserves are in prospect and will be uncovered whenever the demand warrants the further exploration. Moreover, the synthesis of "natural" gas from coal may become feasible in the not-too-far-distant future. If and when exploration efforts are unable to maintain a satisfactory current inventory this alternative source of gas may well become a reality.

The close relationship that exists between natural gas and oil has already made itself apparent in the reserves and production statistics. This relationship is an almost continuous one from source to market. As a result, anything that affects either one also affects the other in some measure. Oil and gas are frequently found together in underground formations. The reserves of each at any one time are the product of exploration efforts that may have been directed primarily to either. Natural gas is also an instrument that contributes to the production of oil. Utilization of natural gas to improve the ultimate oil recovery from reservoirs is a common practice, and gas used for this purpose returns in many cases values far in excess of the average return from fuel uses.

In at least some instances, either oil and gas or the products of each enter the same markets as competitive materials. The chemistry of the two is such that either can be converted to the other should market demand warrant such conversion. Since the modern trend in refining has been in the direction of reconstructing nature's raw materials to achieve desired fuel and lubricant properties not inherent in the crude raw materials, the differences in the physical forms of oil and gas that were previously thought to govern their respective commercial outlets have been somewhat minimized. Both are now merely convenient source materials for carbon and hydrogen. The net effect of this close relationship between oil and natural gas is such that in a free competitive market it not only should lead to definite and related prices based on the raw-material values of each, but also should preclude, to a great degree, consideration of either one separately in matters of reserves, production, and use.

With oil and gas being considered principally as source materials for carbon and hydrogen it becomes apparent that in any long-term consideration of the two materials some thought should likewise be given to alternative sources of these elements. Therein lies the reason for the industry's present interest in coal-conversion processes, since the currently desired products can be made readily from coal whenever the need arises and whenever the economics is such as to justify such a route. With such a proved alternative in prospect, attempted forecasts of reserves or inventories into the distant future have little use except in so far as they may serve to guide and properly time developments directed to new sources for the desired end products.

EQUIVALENT OIL RESERVES IN FORM OF GAS

Although only one commercial plant for the conversion of natural gas into liquid hydrocarbons is currently in existence in the United States, interest in conversion processes has been active during the past few years, and several such plants have been designed. The yield of gasoline by the process when methane is used as the raw material is estimated at about 4 gallons from

1,000 cubic feet of gas. This gives some indication of the approximate over-all efficiency of the process at its present state of development, for the yield figure would imply that only about 40% of the heat content of the methane charged to the process is recovered in the liquid product.

From 1,000 cubic feet of methane, with no allowance for process fuel requirements, it is theoretically possible to obtain about 6.5 gallons of motor fuel. The fuel value of this 6.5 gallons of motor fuel is about 75% of the fuel value of the original 1,000 cubic feet of methane. Therefore, the maximum fuel value theoretically recoverable is about 75%. In practice, however, even with 100% reaction efficiency in the process, some methane will be required for fuel purposes. Consequently, the yield will always be less than 75% of the fuel value of the methane used to produce it. Improved reaction efficiencies, and, particularly, improved techniques of production of synthesis gas in the process will, no doubt, reduce substantially the amount of gas required, with the result that net yields as high as 4.5 to 5.0 gallons from 1,000 cubic feet may be obtained in large-scale operations.

If a yield of 4 gallons of motor fuel from 1,000 cubic feet of gas is assumed to be currently obtainable, the present reserves of natural gas are equivalent to nearly 18 billion barrels of gasoline, a volume equivalent to 60% of the present proved liquid hydrocarbon reserves. If higher than current average but readily attainable yields of gasoline from a barrel of crude oil are assumed, the presently proved fuel reserves expressed in terms of gasoline are divided about equally between oil and gas.

Although the conversion of natural gas may be important from the standpoint of augmenting raw materials for the manufacture of liquid fuels at costs not far from present costs, it cannot be considered an ultimate solution to the question of future fuels. In short, the utilization of natural gas for synthesis of liquid hydrocarbons represents an intermediate, but important, process and, as such, has greater immediate interest than coal. Variations of the basic process using natural gas will undoubtedly find useful applications, particularly where the conversion can be combined with other processes or with existing facilities. The production of natural gasoline and the manufacture of chemicals afford opportunities for such combinations. Without the economic advantages of such combinations, however, the available information indicates that as a means of producing gasoline alone the conversion of natural gas would not be competitive with present refinery operations using crude oil as a raw material under present prices. Moreover, the peak production of gasoline from natural gas by the conversion process will undoubtedly amount to only a very minor proportion of the total gasoline supply of the nation. The comparisons consequently serve primarily to illustrate the close relationship between natural gas and crude oil and the relative importance of each as a raw material.

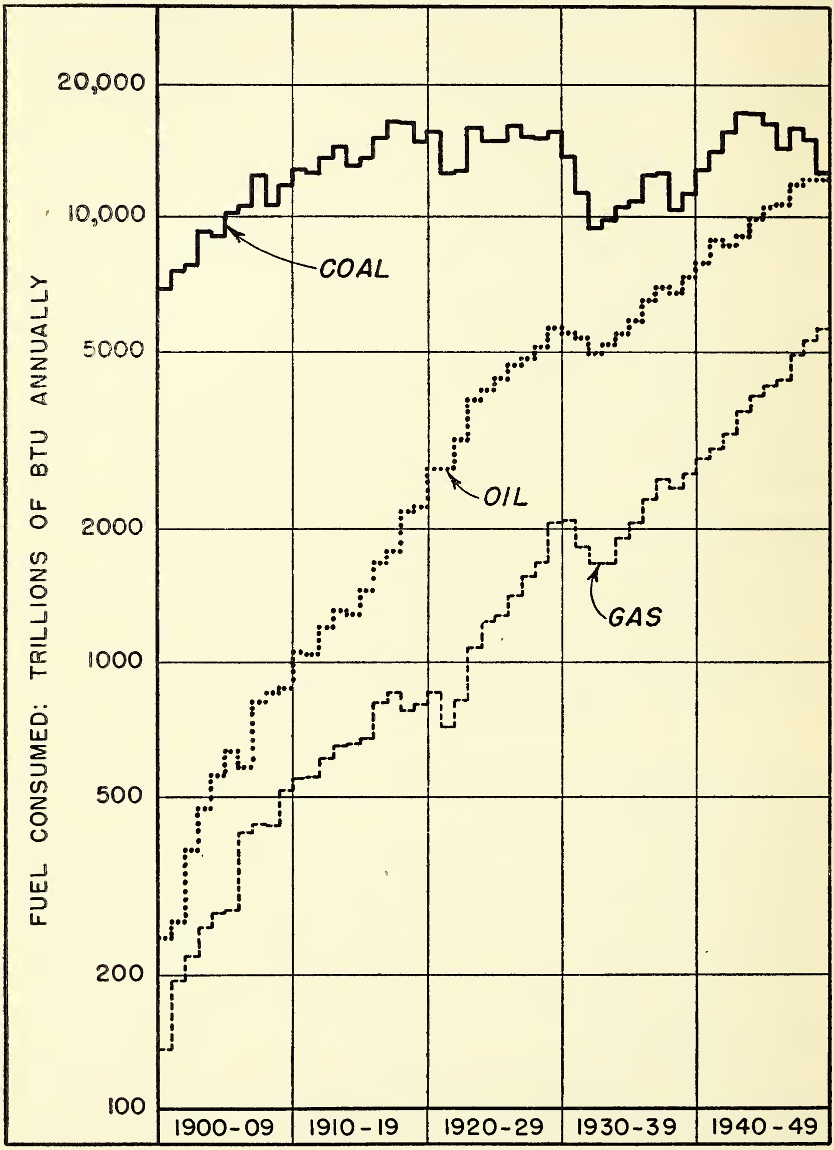
The significance of the Fischer-Tropsch process as a means of extending natural gas reserves also bears mention. Although the process has commanded wide interest as a means of producing liquid fuels from gas or coal, it has equally great possibilities as a means of producing from coal a synthetic "natural" gas to supplement the natural product whenever the demand is such as to require an auxiliary source. Process modifications have been considered that would yield a synthetic "natural" gas near the point of use at costs that would rival the current delivered costs of the natural product at those points. Undoubtedly, process conditions could be devised that would, in the future, yield from coal both synthetic motor fuel and synthetic "natural" gas at prices not too different from those that would result were crude oil used as the raw material at prices somewhat higher than those obtained at present.

RELATIVE IMPORTANCE OF OIL AND GAS AS ENERGY RESOURCES

The tremendous growth of production of oil and natural gas in the United States is impressive, but the production records of these commodities alone do not tell the whole story of the extent to which the economy of the United States has come to depend on petroleum. Perhaps few realize that today oil and natural gas together provide more than half of the total mineral fuel consumed in the United States, their joint consumption now exceeding that of coal. The record of mineral fuel consumption since 1900 is shown in Chart V.

It may be noted from the chart that whereas consumption of coal has not increased significantly since 1917, consumption of oil and natural gas has increased over sevenfold during the interim. This record shows the extreme degree to which the United States today is dependent on petroleum, and emphasizes the importance

Chart V—U. S. MINERAL FUEL CONSUMPTION



of producing oil and gas as efficiently as possible and in orderly response to our needs.

SIGNIFICANCE OF ACCOMPLISHMENTS

The astounding accomplishments in both the discovery and production of oil and natural gas are to a large extent due to the increasing use of scientific methods in exploration and production, and to the development of conservation. During May, 1951, production of crude oil in the United States exceeded 6 million barrels a day. Such a rate of production would have seemed fantastic in 1925. It would not have been possible to sustain it for any length of time as late as 1940. Tremendous waste would have resulted had an attempt been made to produce at such a rate. Today that rate is sustained by adequate proved and developed reserves, which new discoveries are continuously increasing.

During the past fifty years the rate of production of oil in the United States has doubled every eight to fifteen years. In spite of this production, the reserves have not been exhausted, but have continued to keep pace with the production. In this history lies not only a record of achievement, but the key to conservation in its fullest sense.

If at any time in the past the future had been viewed in the light of the facts then available it would have seemed unreasonable to predict a continuation of the past trend. Because of the ever-present problems and difficulties few have ever been so rash as to expect the future to carry progress very much further. A leveling is almost invariably anticipated. The reason for such conservatism is natural and is obvious. Present problems can be analyzed only on the basis of the prevailing state of technology. Unknown and unforeseen scientific accomplishments may be anticipated in the abstract, but, in the absence of foreknowledge, cannot be counted on quantitatively with regard to any specific situation. Nevertheless, the facts are, as the record shows, that at no time in our past history has progress ceased or, other than temporarily, even been greatly retarded.

Why has the tremendous production of petroleum not exhausted our resources long since? The answer lies simply in the scientific and technologic progress that has been made in a competitive environment where incentive and opportunity have fostered innovation and growth. Production has created a demand, and an expanding demand has, in turn, provided an incentive for further production. The process is cumulative. The need to find more oil has called for greater effort, for increasing application of scientific methods, and for greater efficiency in both exploration and production. The capital generated through past production and saved through more efficient methods has made it possible to expand the activity, both physically and technologically. Increased efficiency in recovery has greatly extended the proved reserves that result from a discovery, and the greater reserves have provided additional incentive for still greater efficiency in their recovery.

It is in this manner that conservation has grown directly in a natural but vigorous manner under a system of competitive private enterprise. Its basic need for further growth is a preservation of the incentive that makes it grow.

Chapter III

THE PETROLEUM RESERVOIR

WHY STUDY PETROLEUM RESERVOIRS?

In the early days of the petroleum industry, as in those of most mining industries, little thought was given to the recovery of reserves that could not be secured easily by routine operations. A well was drilled. If it would flow it was permitted to do so at maximum capacity. When the yield dwindled so much that it appeared probable that pumping would increase the daily production, pumps were installed, and were operated until the value of the oil that was recovered no longer equaled the cost of getting it. Presumably, few operators realized that in the fields which they abandoned as unprofitable far more oil remained in the productive underground formation than they had recovered from their wells. Anyway, why should they bother when new flowing wells could be drilled elsewhere and quick profits could be made?

Perhaps the greatest single influence that served to modify this attitude was the Bradford field of Pennsylvania, where water, accidentally allowed to invade the oil sand, rejuvenated parts of the field that were thought to be exhausted, and proved that when the original wells were abandoned as unprofitable millions of barrels of oil remained in the oil sand. More than that, it proved that both the volume of the oil and the cost of recovering it were such that new operations in this depleted field would be financially attractive.

Subsequently, determinations of the porosities of reservoir rocks in many fields, and computations of the space that had, presumably, been occupied by oil before the wells were drilled, revealed that in many of these fields not more than 15 or 20 per cent of the oil in place had been recovered before the yields of the wells became so low as to make continued operation impracticable. It was felt that recoveries should and could be improved. The result has been a remarkable increase in the amount, and improvement in the method of reservoir study, and great advances in reservoir engineering.

During the past thirty years the engineers and geologists of the petroleum industry have learned how to estimate with reasonable accuracy the total amount of oil and gas in any underground reservoir. They have also learned that the recovery of that oil and gas depends on the nature, number, and continuity of openings in the reservoir rock; upon the chemical and physical composition of the rock; upon what may be called the geometry of the reservoir rock within the limits of any oil field; on the forces that exist or that may be applied to cause the oil and gas to move through the openings in the rocks; on the amount, distribution, and composition of the water which is found distributed through all reservoir rocks; and on the physical and chemical properties of the oil and gas.

THE PETROLEUM RESERVOIR

An underground petroleum reservoir comprises space in which petroleum has accumulated, together with barriers that prevent the petroleum from escaping from the space. In its fundamentals, it does not differ from any reservoir or container of fluid, either above or below ground.

Part or all of the petroleum from an underground reservoir may be withdrawn or may escape if the reservoir is opened artificially by bore holes or shafts, if it is breached by natural agencies, such as faults, fissures, or the removal by erosion of overlying strata, or if it is tilted by earth movements so that upward movement of the petroleum through permeable beds becomes possible.

The storage space in an underground petroleum reservoir is provided by openings in rocks. Since such openings are, in general, very small, many must be interconnected if they are to form a reservoir of significant magnitude. These openings are confined or restricted by the rock in which they occur. The particular stratum or mass of rock in which the oil-filled openings exist may appropriately be called the reservoir rock. The barriers which prevent the petroleum from escaping from the reservoir demand a combination of geological conditions that will bar either upward or lateral movement of the fluid. Geologists refer to such combinations of conditions as "traps," since they trap or confine the oil and natural gas.

Petroleum in the earth will move upward unless it is restrained, so the "trap" must have an impermeable roof or "cap" above the interconnected openings. It must be impossible for the petroleum to escape laterally, so the attitude of the reservoir rock must be such that the petroleum would have to move downward to escape, or else the interconnected openings must be confined on the sides as well as above by impermeable barriers. The bottom of the "trap" may be either permeable or impermeable rock, since the openings in almost all rocks below the level of shallow ground water are filled with water, and petroleum will not force its way downward through water-filled rock.

The foregoing description applies to underground petroleum reservoirs, large or small. For practical purposes we are primarily interested in those from which oil or gas can be recovered and sold for more than the cost of getting it. In the vernacular of the petroleum industry an accumulation of petroleum is classed as either "commercial" or "non-commercial." An exploratory well may encounter oil or gas but, nevertheless, be plugged and abandoned if it appears that for any reason it is not "commercial"; that is, that the amount of oil to be expected from that well will not justify the expense entailed in bringing it to the surface of the ground. Old wells which may have produced thousands of barrels of oil are abandoned when their operation is no longer "commercial."

Obviously the classification of an underground petroleum reservoir as "commercial" or otherwise involves factors which can and do change. An increase in the price of oil or gas can, overnight, convert a non-commercial into a commercial well. The cost of drilling may be lowered by development of new tools or techniques, or simply by experience that will permit avoidance of delays and difficulties; as a result, profit may be realized from what appeared to be an unpromising operation. Improved knowledge of reservoir conditions and of reservoir displacement forces may permit the recovery of more oil per well than originally seemed probable and this may convert a seemingly hopeless operation into a "commercial" one. One of the functions of reservoir geology and reservoir engineering is to convert "non-commercial" occurrences of petroleum into profitable oil and gas fields. Occasionally, a discovery that appears to be "commercial" may be revealed by more complete information to be "non-commercial."

Of course, the factors and techniques which may convert an unprofitable to a profitable operation may also be applied to large fields that would be classed as "commercial" even though they were unskillfully and carelessly operated. The dividends reaped by the operator, the royalty owner, and the nation when knowledge and skill are applied to increase the recovery from large fields are proportionately great.

Reservoir Space

The reservoir space is provided by openings in the reservoir rocks. These openings are commonly called "porosity." Technically, this term covers all interstices in rocks, but mention of a "pore" brings to mind a minute opening; consequently, in petroleum technology the term "porosity" should probably be reserved for the intergranular openings in rocks made of particles or fragments of mineral matter, and for the openings, large or small, within the body of such rocks as limestones and dolomites. The precedent of usage permits application of the term to large openings in calcareous rocks, since "cavernous porosity" has often been mentioned and it is excellently descriptive.

Distinction must be made between total porosity and effective porosity. The oil man and the petroleum technologist deal with petroleum that will move into a well, and such movement requires a continuous channel or passageway. The effective porosity is the interconnected porosity through which liquid and gas can move.

The pores in the clastic rocks are the openings between the closely packed grains or fragments of diverse shapes and different sizes. If the grains were all perfectly spherical and of uniform size the pores in cross section would tend to be either roughly diamond-shaped, except that the sides would be curved, or else would be triangles with curved sides. The odd shapes and sizes of the individual rock particles result in pores of extremely irregular outline, but, characteristically, a cross section will terminate in points and microscopically thin edges. The pores in limestones or dolomites commonly have been modified and in part created by the dissolving action of circulating water. They may be circular in cross section, but as a rule they have ragged, irregular cross sections into which protrude points or knobs of the surrounding rock.

In addition to openings between individual particles in the clastic rocks and the irregular openings that occur in limestones and dolomites, all sediments have bedding planes between individual layers. The layers of rock may be compared to a stack of books or magazines, some thick and some thin, in which the bedding planes would correspond to the contacts between the different books and magazines in the pile. Some rocks are so massive that bedding planes are few, but usually there are many of these sheet-like layers. For example, there are known occurrences where sandstone and shale alternate, each layer but an inch or two thick, so that in 50 feet of such rocks there might be 600 or more bedding planes. In limestones and dolomites, openings along the bedding planes may be enlarged by solution and their importance as reservoir space correspondingly increased. In addition to the bedding planes which occur at the tops and bottoms of individual strata, there is what is known as "cross bedding," which is at an angle to the tops and bottoms of the individual strata. Such "cross bedding" may provide thousands of bedding planes in a layer of rock that is only a few feet thick. Figure 1-A illustrates bedding planes in limestone, and Figure 1-B illustrates cross bedding in sandstone.

Openings known as joints are found in all rocks. In sediments they tend to be perpendicular to the bedding planes and to occur in fairly regular systems, most commonly in rectangular pattern. In metamorphic and igneous rocks they may incline in any direction. They may affect a single thin stratum, as in the Checkerboard Limestone of Oklahoma, which received its name because of the uniformity with which it was divided by joints into squares like the markings on a checkerboard. Such joints may penetrate only a comparatively few feet of rock or they may split the rock for hundreds of feet. Individual joints may be 100 feet or more apart or, conversely, they may occur at intervals of an inch or less. As a rule they are most numerous in rocks that have been greatly deformed or folded, but extensive and closely spaced joint systems are known in some strata that are gently inclined or even flat. Figure 2 illustrates joints in sandstone. Waters circulating along joint systems may enlarge them. This is especially true of joints in such soluble rocks as limestones or dolomites. Often, however, these waters tend to deposit minerals, such as calcium carbonate and iron oxide, which may partially or completely fill the space originally formed when the rocks divided.

In addition to true joints, there are fissures, which may traverse the rocks at any angle to the bedding. If the rock on one side of a joint or fissure is elevated or depressed with respect to that on the other side, the rock is said to be faulted. Fault fractures may penetrate thousands of feet of rock, and the rock adjacent to the fracture along which the principal movement occurred may be intensively shattered. It is known that there have been extensive movements of oil along fault planes. Many oil seepages are associated with them. One of the best known instances of extensive movement of oil along fault planes is in the Homer field of Louisiana, where the evidence indicates that oil found in the Nacatoch sand migrated upward along a fault that breached the underlying Blossom sand

and permitted most of the oil in the Blossom sand on one side of the fault to move to a new reservoir.

Some of the oil fields, such as the Panuco field of Mexico, the Zwolle field of Louisiana, and the Florence field of Colorado, are believed to be almost, if not entirely, dependent on joints or fissures for their oil-containing reservoir space. In fields where the reservoir rock is metamorphic or igneous a very large part of the reservoir space must be in fractures rather than in openings between mineral grains. In some fields, such as West Edmond of Oklahoma and the deep horizon of the Big Lake field of Texas, joints or fractures are an important part of the reservoir space but are supplemented by true porosity in the shattered rock. Openings of this type must be present in most fields and must contribute more or less to the reservoir space, but rarely has it been possible to secure the evidence that would permit even an approximate estimate of the amount they contribute to the total space in the reservoir. For this reason the possibility that joints may contain a large amount of oil is commonly ignored by those who estimate the amount of oil that should be recovered from pools or fields.

Since joints and fissures may be sufficiently "open" to permit very free movement of fluid or, on the other hand, may be merely hair-line fractures along which fluids creep with difficulty, wells that secure their oil from such reservoir space range from spectacular "gushers," capable of yielding many thousands of barrels per day, to wells of low yield. However, the acre-foot yield in fields that depend exclusively on "fracture porosity" is invariably low, and such fields must cover a large area or have a very thick oil-bearing section if they are to be important. In such fields a single well will drain an extensive area, and closely spaced wells are likely to be unprofitable unless two or more such wells chance to open fissure systems that are not connected.

Joints and fissures along which fluids may move freely and that extend below the water level of an oil field may be responsible for the early appearance of water in wells that seem to be more favorably located with respect to the geometry or "structure" of the field than other wells that continue to make water-free oil. Such water incursion along fracture systems can be detected, or at least suspected, if the wells that show water have a linear relationship. This was demonstrated by early water encroachment in one of the pays of the Salt Creek field of Wyoming. In the Reed City pool of Michigan the pattern of water encroachment strongly suggests that edge

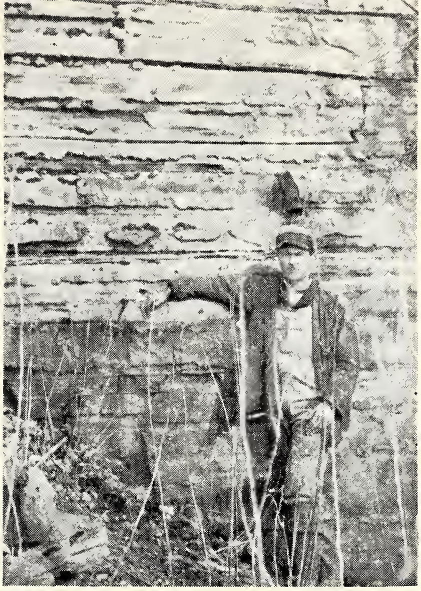


Fig. 1-A—Bedding Planes in Limestone (Cherty Limestone, Probably Spergen or Warsaw, along Tennessee River, Galloway County, Kentucky—Photograph Courtesy K. C. Heald)

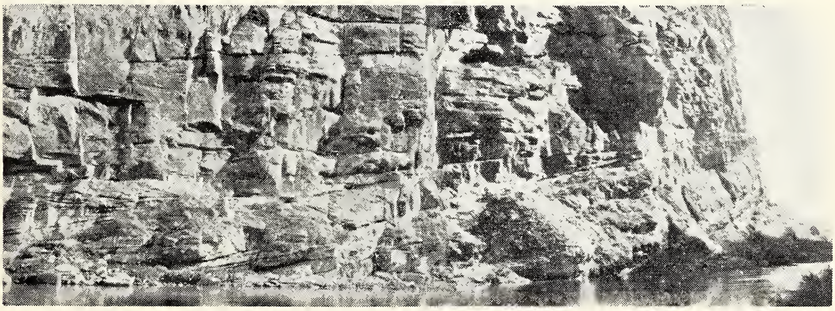


Fig. 1-B—Cross Bedding in Sandstone (Tensleep (?) Sandstone in Alcova Canyon—Photograph Courtesy K. C. Heald)

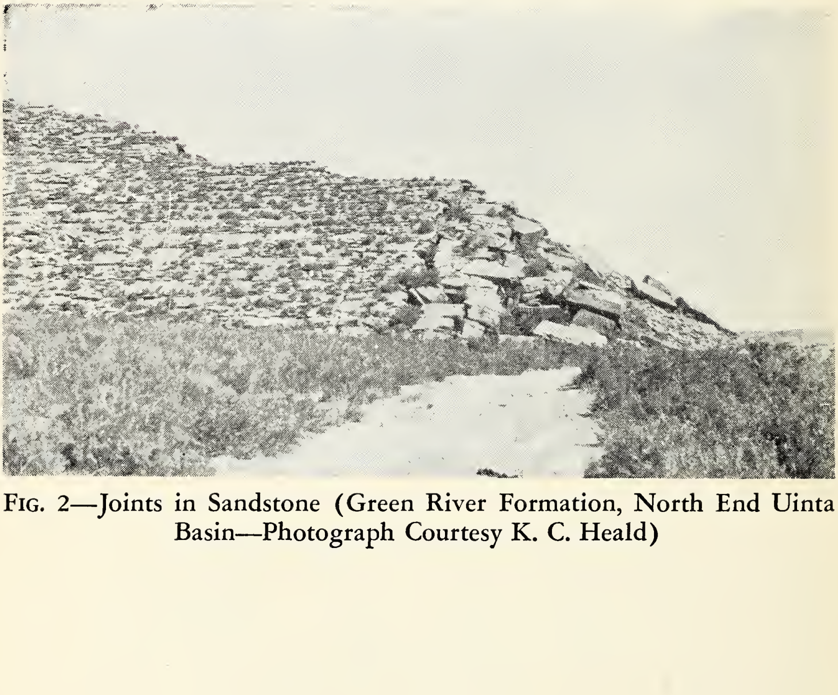


FIG. 2—Joints in Sandstone (Green River Formation, North End Uinta Basin—Photograph Courtesy K. C. Heald)

water moved into the interior of the field along fractures. (Figure 3). There is no known remedy for such localized water incursion except to shut in the affected wells in the hope that oil will again occupy the fissure along which the water migrated.

PERMEABILITY

The term permeability, when applied to petroleum reservoirs, denotes that characteristic of the rock which determines the rate at which a fluid will pass through the reservoir rock under a given pressure gradient. Natural gas will move more easily than will even a light oil, and a light oil more readily than one that is thick and viscous. Permeability measurements permit comparisons of the relative ease of movement of fluids through different reservoir rocks. As will be explained in Chapter V, in order to determine quantitatively the rate of movement of a particular fluid through a particular portion of reservoir rock it is necessary to know not only the permeability of the rock, but the viscosity of the flowing fluid, the amounts and nature of other fluids present, and the vertical angle of the flow. Knowledge of the permeabilities of all parts of a reservoir is very important to the petroleum engineer. A single permeability measurement in a petroleum reservoir cannot be considered very significant, but such measurements distributed throughout the reservoir rock, both horizontally and vertically, furnish extremely important control that can be used to improve recoveries if suitable production practices are followed.

It is customary to secure permeability measurements that will indicate the rate of movement of fluid parallel to the bedding of the sediments, as well as measurements transverse to the bedding. The measurements transverse to the bedding cannot be used directly to determine the rates of vertical fluid movement in a reservoir. Both experience and geological considerations indicate that fluids will move parallel to the bedding much as would be anticipated from the permeability measurements, but that there are obstacles to the movements transverse to the bedding that are not revealed by laboratory work. Most of the oil and gas fields of the world are in sedimentary rocks, and most sedimentary rocks contain bedding planes or partings on which commonly, although not invariably, there is a film or selvage of clay that may be an effective barrier to the free movement of oil or gas from the rock on one side of the bedding plane to the rock on the other. Even where there is no clay film there may be induration or cementation at the bedding plane, which

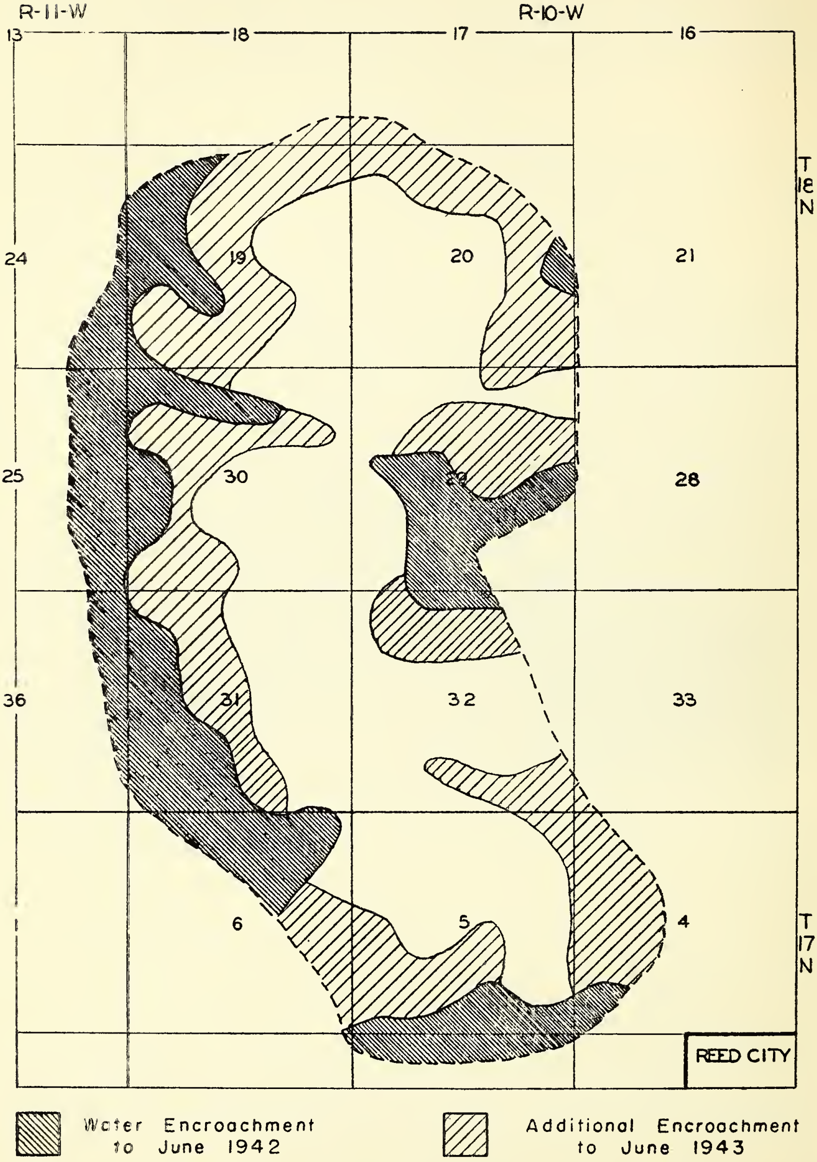


FIG. 3—Water Encroachment, Reed City Pool, Lake and Osceola Counties, Michigan

will reduce the permeability. These bedding planes are believed to be responsible for the observed phenomenon of very low vertical permeability as manifested by the behavior of wells even though the measurements in the laboratory on short cylinders or "plugs" of the reservoir rock may have shown high permeability values. The samples tested in the laboratory rarely include bedding planes. In the process of coring to secure samples, the rock tends to break along clay partings and bedding planes so that the fragments that are available for measurements do not include the barriers to transverse movement of fluids.

TYPES OF RESERVOIR ROCK AND ASSOCIATED RESERVOIR SPACE

The following discussion does not pretend to catalogue completely all kinds of reservoir rock, nor to describe all variations of reservoir space. No effort is made to adhere to exact scientific terminology. So far as possible the terms used are familiar to laymen as well as to specialists. Also, the reader should be advised that there are multitudes of variations and hybrids of the types of reservoir rocks that are listed. Thus, instead of having a rock that may properly be classed as either a sandstone or a limestone, the geologist may be hard put to decide whether it should be called a sandy limestone or a limey sandstone, or, perhaps, whether he should call a rock an arkose or an arkosic conglomerate.

Clastic Rocks

Clastic rocks include all those that are made of fragments or of distinct, separate particles. Most of these rocks have fragments of quartz as their most abundant constituent, but some are in part or exclusively made from fragments or particles of limestone, or dolomite, or feldspar, or volcanic debris, or even comparatively rare minerals such as black magnetite, red garnet, or green glauconite (greensand).

Silts and Siltstones

A pure silt is an accumulation of very tiny particles of rock that range in diameter from a maximum of 1/16 of a millimeter to a minimum of 1/256 millimeter in diameter.[1*] Particles smaller than

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***Superscripts refer to publications listed at the end of this chapter.**

the minimum mentioned are classed as clay.[1] A siltstone is a silt whose individual particles have been fastened together by some natural cement. The dominant mineral that forms the grains in practically all siltstones that are also reservoir rocks is quartz, but a multitude of other minerals are present in minor amounts. Unfortunately, many siltstone reservoir rocks contain much impurity in the form of clay, and this tends to make silts and siltstones among the least satisfactory of the reservoir rocks. The clay tends to plug or reduce the sizes of the openings between the particles of silt, to increase the connate water content, and may swell when touched by fresh drilling water. The porosity of siltstones tends to be high, and the possible content of fluid correspondingly great. This does not mean that the amount of oil or gas in place per cubic foot of rock will be greater than in a coarser-grained rock, because, as a rule, there is more connate water in very fine-grained than in coarse-grained rocks. Connate water is water that exists along with oil or gas in reservoir rocks. If clay impurities are high, the content of connate water may be further increased, since tests have indicated that the percentage of connate water tends to vary directly with the amount of clay in the reservoir rock.[2] Permeabilities are low, as a rule, since petroleum moves with difficulty through the tiny openings between the grains of silt, and a high connate water content also reduces permeability to oil and gas. If clay is present, permeability is further impaired. Initial productions from such rocks may be promising, but unless production rates are controlled very carefully the output declines rapidly, and even with the best production practice it is difficult to recover a high percentage of the original oil content.

Siltstones are productive in many areas, but in most of the fields where they are present oil is also produced from rocks with more favorable characteristics. The Santa Barbara field of eastern Venezuela and the Leeville field of LaFourche Parish, Louisiana, are instances of fields that have obtained part of their production from siltstones.

Sands and Sandstones

A pure sand is an aggregation of small, individual mineral grains ranging in greatest dimension from a maximum of 2 millimeters to a minimum of 1/16 of a millimeter. Particles larger than the maximum are called gravel, those smaller than the minimum are termed silt or, if extremely small, clay. Depending on the admixture of larger or smaller constituents, a sand may be described as gravelly or silty.

A sandstone is a sand whose particles have been bonded by some natural cement. The most common of these bonding materials are silica, calcite (lime), and iron oxide, but instances are known where the bonding material is tar or some other hard or viscous organic substance. The individual particles are commonly quartz, with comparatively minor percentages of other minerals, but in some instances fragments of limestone, magnetite, or other minerals dominate.

The shapes and sizes of the openings in sands and sandstones are controlled by the uniformity in size and shape of the individual grains, the presence of silt and clay, and the amount and nature of cementing material. If the grains were all perfectly round and of uniform size the openings between the grains would be uniform and would form a continuous network. However, such sands are not known in nature. In general, the maximum dimension of any pore or opening is less than the maximum dimension of the largest sand grains. Departure from roundness permits closer packing of the grains. Irregularity in size permits small grains to fill the openings between the larger ones. Occurrence of silt or clay will tend further to plug the chinks and crannies. Finally, the cementing material which binds the grains of sandstone may further reduce the size and number of openings, and may, if carried to an extreme, render sandstones impermeable and interrupt the permeability connection between different parts of a reservoir rock.

The porosities of unconsolidated sands may be as high as 50 per cent. Those of sandstones may be very low, but if they are made of clean, fairly well rounded, and uniform sand that is only slightly cemented the porosity may be 40 per cent or more by volume. If these pores were all filled with oil a cubic foot of the rock would contain about 0.07 of a barrel, and a layer one foot thick and an acre in extent would contain about 3,100 barrels. The permeabilities of clean, well-sorted sands are very high. Those of sandstones are lower, but the more permeable layers or streaks in a sandstone will often approach the permeabilities of unconsolidated sands.

The connate water content in sands and sandstones, as in other rocks, is controlled more by such factors as texture, impurities, permeability, and proximity to edge and bottom water than by the mineralogy. It probably is rarely less than 10 per cent. Contents of connate water greater than 50 per cent have been recorded, but there may be a question as to whether some part of this water might not more properly be classed as "free" or formation water than as connate water. Sandstones with good permeabilities and with recorded water contents of 50 per cent have been excellent reservoir beds and have yielded great volumes of water-free oil.[3]

The characteristics of sand and sandstone reservoirs will permit initial productions of many thousands of barrels a day if adequate reservoir pressure is available and if the sands are highly permeable. It is believed that 50 to 80 per cent of the oil from such reservoirs can be recovered if permeability and structural conditions are favorable and if proper use is made of the displacement agents naturally available or that may be supplied. On the other hand, there are many sand reservoirs in fields now abandoned or that are yielding insignificant amounts of oil that probably still contain 80 per cent or more of the oil that was originally in place.

Among well-known examples of fields that produce from sand reservoirs are the East Texas field of Texas, the LaFitte field of Louisiana, the Oklahoma City field of Oklahoma, the Kettleman Hills field of California, and most of the fields in Venezuela.

Conglomerates and Breccias

Conglomerates and breccias differ from sandstones only in that they contain many fragments larger than 2 millimeters in greatest dimension. To the layman they are rocks that contain pebbles and, indeed, some of the individual fragments may be boulders. Even a sandstone with a sprinkling of pebbles may be classed as a conglomerate, but for our purposes a conglomerate and a breccia are rocks composed primarily of pebbles or larger fragments. Conglomerates are composed of rounded fragments, and breccias are made of angular fragments. The component pebbles may be of any kind of rock. Quartz is the most common constituent, but conglomerates and breccias in which the fragments are limestone are reasonably common, and those made of fragments of igneous rocks and of chert are also well known. As a general rule the interstices between the pebbles are filled with particles of sand size with a very minor amount of silt and clay. However, there are some rocks that contain a substantial number of pebbles and cobbles and would, therefore, be classed as conglomerates that are very "dirty."

The porosities of slightly cemented conglomerates and breccias are, as a rule, lower than those of sandstones or siltstones that are not strongly cemented. The permeabilities of the coarse-grained clastic rocks are, however, higher than those of any other reservoir rocks except some limestones and dolomites. Both porosity and permeability may be reduced if fine-grained material or clay fills the interstices between the pebbles, and if the rock is strongly cemented the permeability may disappear entirely. This is, of course, true of all reservoir rocks.

The connate water content of clean conglomerates and breccias whose large openings are not filled with fine material or cement is lower than that of sandstones or siltstones, and the percentage of oil or gas in the openings in the rocks is correspondingly higher. Good initial productions and recovery of a comparatively high percentage of the original oil content are to be expected from such reservoir rocks. If, however, sand or silt fills the chinks between the larger fragments the initial productions and ultimate recoveries should be comparable to those from sandstone reservoirs, and the lower total porosity will result in lower recovery from an acre foot of producing formation than from a sandstone reservoir of equal permeability.

Conglomeratic sandstones, and layers of conglomerate associated with sandstone, are found in many oil fields, but instances of conglomerates that form the only pay in a field or that dominate an important reservoir in a multiple-pay field are relatively rare. A good example is found in the Wherry field of Rice County, Kansas, where the reservoir rock is a conglomerate composed of rounded pebbles and boulders of chert.[4] One of the reservoir beds in the Playa del Rey field of Los Angeles County, California, is a conglomerate of pebbles, cobbles, and boulders of schist.[5]

Arkoses

Arkoses, commonly referred to as "granite wash" by oil men, differ from sandstones or from conglomerates only because 25 per cent or more of the rock is the mineral feldspar. There are several kinds of feldspar, but most of the arkoses that serve as reservoir beds in known oil fields are made up in large part of what is known as orthoclase feldspar. This mineral is commonly pink in color and its presence gives a characteristic pinkish or reddish tinge to the rock. Just as rocks made of siliceous fragments may be classed as siltstone, sandstone, or conglomerate, depending on the sizes of the constituent particles, so may arkoses be comprised of fragments ranging in size from microscopically small to cobbles or boulders. The openings in arkoses are quite comparable to those in other clastic rocks of similar texture if the arkose is unaltered. However, feldspar decomposes rather easily and forms clay, so that a rock that was originally formed of hard grains may be modified to one that is a mixture of hard grains and pebbles of clay. Compaction or minor movements of the earth may force some of this clay into the original interstices between the grains. Also, unfortunately, some of the clay may be of a variety that will swell if it is wet with fresh water, so that the fluid from drilling mud may affect the clay, causing it to swell and plug openings in the rocks. For this reason, many rocks that are classed as arkoses are less satisfactory as reservoir rocks than siltstone, sandstone, or conglomerates of comparable texture.

Perhaps the best known instance of oil and gas production from an arkose is in the Texas Panhandle. The gas in Wheeler County is for the most part found in arkose. Both gas and oil are produced from arkose in Carson County, and it is a gas reservoir in northern Potter County.[6]

Oolites

Oolites are rocks comprised of tiny, round grains of limestone. The name means "eggstone," because the rock looks like the roe of a fish. The grains of limestone accumulate just as do grains of sand, and the resulting rock is not appreciably different in texture from a sand or sandstone formed of spherical sand grains. Reservoir beds that are true oolites are rare, but oolitic limestones, which are limestones with oolites sprinkled through them, are common. The oolitic limestones, however, cannot be considered clastic rocks but rather as a type of limestone. The grains in true oolites compare in size with the grains in a sand or sandstone, and the openings between the grains form a continuous network. Such rocks usually have a very high porosity and also excellent permeability. The content of connate water should be comparable to that in a medium-grained sand. Initial production from such reservoir rock can be very high, and the percentage of oil in place that is recoverable is also high as compared with most other types of reservoir rocks.

The McClosky pay of Illinois is an oolitic limestone that in places grades into a true oolite. Perhaps one of the best instances of production from a true oolite is the Schuler field, of Union County, Arkansas, where the Reynolds oolite zone in the upper part of the Smackover Limestone formation is one of the important producing horizons.[7]

Tuffs

Tuffs are composed of fragments of rock ejected by volcanoes and that have accumulated either by settling through the atmosphere or by falling into water. Naturally, the constituents are varieties of igneous rocks and minerals formed under high pressures and temperatures, but, since some of these materials can be altered easily, tuffs may appear to contain a high content of clay, which is simply the degradation product from the original minerals. Of course, if the volcanic material fell into moving water it may have been mixed with clay, sand grains, or other materials present in the water.

As a general rule, tuffs are poorly sorted, and the high percentage of very fine material makes permeability low, although porosity may be high. They are comparatively unimportant as reservoir beds and are included merely to make the tabulation of clastic rocks reasonably complete. It has been reported that the oil fields of Japan draw their oil from tuffs, but available descriptions permit the possibility that there may be beds of sandstone associated with the tuffs. A more definite instance is the Hilbig field, of Bastrop County, Texas.[8]

Shales

Shales are more or less lithified rocks whose "constituent particles are predominantly of the clay grade."[9] Those encountered in oil fields range from soft, "punky" rocks which are penetrated with the utmost ease, to hard, consolidated, resistant strata. The dominant constituent is aluminum silicate, but they may contain considerable quantities of sand, in which event they are called sandy shales, or of lime, which will lead to designation as limey shales. Iron oxide is a very common constituent, and many other minerals are present in minor quantities.

Shales are very fine-grained, since the particles that comprise the rock have an average greatest dimension of less than 1/256 of a millimeter. Their porosities are usually high, but, because of the microscopically small interstices between individual grains, their permeabilities are negligible. They may have a high fluid content of water or even of petroleum, but the fluid will move from the rock into a well or other opening at a negligible rate, if at all. There are a few oil fields in which shales are the reservoir rock, but in these fields the oil is recovered from fissures or fault planes, such as may occur in any type of rock, and not from the intergranular porosity of the shale. A classic example is the Florence field of Fremont County, Colorado. Minor quantities of oil have been recovered from shale in the Salt Creek and Teapot Dome fields of Wyoming, and from erratic occurrences elsewhere in the United States.

Non-clastic Sediments

"The non-clastic sedimentary rocks in general are derived through the agency of some form of life or are chemical precipitates. They are only indirectly derived from other rocks through their disintegration and redeposition."[10] The only non-clastic sediments that are important reservoir rocks are the limestones and dolomites. Small quantities of oil have been found in such non-clastics as gypsum, anhydrite, and salt, but these occurrences are so rare that they may be ignored.

Limestones and Dolomites

Limestones are comprised principally of calcium carbonate, which, in its pure form, is the mineral calcite. Dolomites are indistinguishable from limestones to the casual observer but, when pure, are made of the double carbonate of calcium and magnesium, instead of calcium carbonate as in limestones. The distinction between these two similar rocks is far from academic to the petroleum geologist or engineer, for they differ in their tendencies to develop and retain porosity, and also in their response to treatment with acid, which may be used to enlarge the openings in these acid-soluble rocks. Very often these rocks when found in petroleum reservoirs are neither pure limestones nor pure dolomites, containing too much magnesium to permit their classification as limestones, and too little magnesium to qualify as pure dolomites. Such rocks are more properly called dolomitic limestones.

Limestones and dolomites are usually dense, compact rocks, although occasionally beds are so contaminated with clay as to be quite "earthy." Most of them are hard and tend to be tough, but very compact, fine-textured limestones may be brittle and may break with a glass-like fracture; at the other extreme, chalk, which is a form of limestone, is soft. In texture they range from a mass of easily distinguishable, closely interknit crystals to a uniform smoothness in which separate particles cannot be detected. Most of them contain impurities, the most common of which is silica in the form of chert or flint, which may occur in tiny, scattered particles, in nodules, or in layers.

The reservoir space peculiar to these rocks consists of irregular, ragged, ramifying channels that range in size from sub-microscopic to cavernous. These channels may be so numerous as to give the rock a "rotten" appearance, or so scarce that only scattered pinpoints of oil appear on the surface of a freshly cut core. Some of these rocks, particularly dolomitic limestones or dolomites, have a network of interconnecting openings between individual crystals that make up the rock. Depending on the number and sizes of individual openings, the porosity of a limestone may range from almost zero to a figure greater than that for any clastic rock, and the same is true for permeability. The largest oil wells in the world in terms of daily capacity produce from limestone or dolomite reservoir rocks in which the openings are so large that the oil flows rapidly and freely into the well bore.

The range in producing characteristics of these carbonate rocks is as pronounced as is the range in size and number of reservoir openings. Those with cavernous porosity surrender a very high percentage of their oil with a minimum of difficulty; those with very small openings may require extraordinary skill in handling the reservoirs in order to recover more than a small fraction of the oil in place. The range in the size of openings in the carbonate reservoir rock of a single pool imposes difficulties greater than must be overcome in fields that draw their oil from clastic rocks, whether the expulsive agents originally present in the reservoir are used, or whether they are supplemented artificially. Limestone and dolomite reservoir rocks are a challenge and an opportunity to reservoir geologists and engineers.

Limestones, dolomitic limestones, and dolomites are the reservoir rocks in many of the world's most important oil fields. Most of the fields of west Texas and southeastern New Mexico; the Luling, Darst Creek, and minor fields of central Texas; many fields in Illinois; practically all the fields of Michigan; the old fields of the Lima-Indiana district of Ohio and Indiana; the most important fields of western Kansas; and many others throughout the United States secure their production from such rocks. Most of the production of Mexico, of western Canada, of Iran, of Iraq, and of Arabia is from reservoir rocks of these types.

Chalk

Chalk is a form of limestone made from accumulations of the tests or shells of microscopic organisms. Anyone who has used a blackboard is familiar with this rock in its pure form. It has high porosity but practically no permeability. It may, therefore, contain much oil, but it is reluctant to surrender it. The recoverable oil in fields where chalk is the reservoir rock is believed to occupy fissures, joints, bedding planes, and, to a limited extent, solution cavities. Chalk forms the reservoir rock in the Zwolle field, of Sabine Parish, Louisiana, and also in parts of the Caddo field, of Caddo Parish, and the small fields along the Balcones Fault Zone, in east-central Texas. As a reservoir rock it is relatively unimportant.

Igneous Rocks

Igneous rocks are rocks that were once so intensely heated that they melted, like ore in a blast furnace. They took their present form when they cooled, either when they were poured in the form of lava from a volcano or other vent, or below the surface as sheets or tabular masses between layers of other rocks. Rarely do they contain oil. In most oil fields, granite, which is an igneous rock, is known as the "farewell rock," below the surface of which drilling will be fruitless. Oil in small amount has been observed in igneous rocks in many localities, but commercial production has been found only in a few fields where the igneous rocks are closely associated with sediments. Some oil is produced from the granite underlying the more dependable sedimentary reservoir rocks in the Panhandle field of Texas. The Rattlesnake Hills gas field of the state of Washington finds its gas in basaltic lava. In the Furbero field of Mexico some oil has been produced from an igneous rock called gabbro.

Metamorphic Rocks

Metamorphic rocks are those that were originally either igneous or sedimentary but which have been greatly altered by such natural agencies as heat and pressure. Some of their original characteristics have been destroyed and new ones have been acquired. Of the many varieties of metamorphic rocks only schists, serpentines, and quartzites are known to be reservoir rocks in existing oil fields. In every instance they are closely associated with sediments in which the oil is believed to have originated, and in most instances oil is also produced from sedimentary reservoir rocks that lie above the oil-bearing metamorphic rocks.

Schists

Schists may be formed from the alteration of either shales or certain kinds of igneous rocks. They are characterized by the development of platy minerals such as mica, and the rock is a mass of crystals. When these rocks are unaltered they are dense, with very low porosity and permeability. However, they may contain minerals that are quite easily altered by circulating waters, and such alteration may readjust the rock texture in such a manner as to create porosity and permeability. Such porosity and permeability may be reasonably continuous, making the rock comparable, in its reservoir characteristics, to a "dirty" conglomerate or to some types of limestones. Initial well productions from such rocks may be as high as 5,000 barrels a day, but recovery from an acre foot of reservoir rock is relatively low. The irregular shapes and distribution and the wide variation in size of reservoir openings make control of the movement of fluids in the reservoir highly important if loss of much of the oil in the smaller openings is to be avoided.

Schists are reservoir rocks in several fields of the Los Angeles Basin and in the Mountain View field of the southern San Joaquin Valley of California.[11] In each of these fields there are shallower sedimentary reservoir rocks that contain oil, but there is no geological reason why porous and permeable metamorphic rocks such as altered or fractured schists should not contain oil, even if there are no other reservoir rocks associated with them, if they are in contact with good source beds.

Serpentines

Most serpentines are formed from the alteration of dark-colored igneous rocks. They are characterized by an abundance of the green or red mineral serpentine, are massive, and tend to be tough, but neither very hard nor very soft. In the fields where serpentine is the reservoir rock it has irregular porosity, so that unproductive locations may be surrounded by producing wells. On the other hand, some streaks of porosity are so continuous that adjoining wells interfere with each other, the production from one decreasing that from another. Many of the pores or openings are large enough to be detected easily without a lens or microscope, but others are very tiny. Part of the effective porosity is in fissures or fractures. Measurements on individual samples have indicated porosities of 32 per cent or more,[12] but 20 per cent is, perhaps, a more probable figure for the average oil-yielding serpentine.[13] Actually, there are far too few published data to justify more than a guess concerning porosity, and this is even more true of permeability. Figures have been published on water content,[12] but the water that was measured might have been in part or entirely drilling water from the wells, and the figures are not regarded as significant.

Initial productions as great as several thousand barrels a day have been recorded for wells securing production from serpentine reservoir rock, but such large producers may be offset by wells good for but 10 to 25 barrels a day. The available records of average pay thickness are not sufficiently precise and reliable to justify an estimate of yields from an acre foot, but these yields are comparatively low, for in none of the fields where serpentine is the reservoir rock is there a natural water drive to supplement the dissolved gas as an oil-displacing agent. Also, the porosity is so erratic that some porous lenses may have escaped the drill entirely, and a good deal of oil may be trapped in zones of low permeability.

Oil has been produced from serpentine reservoir rocks in about 13 fields in Bastrop, Caldwell, and Williamson Counties in central Texas. The most important has been the Lytton Springs field of Caldwell County.[14]

Quartzite

Quartzite results from the metamorphism of sandstone or conglomerates. The original grains may not be distinguishable, and the original openings between the grains have been filled with silica so that the rock is a solid, dense mass, with practically no porosity or permeability. If such a rock is to serve as a reservoir rock, openings must be created by fissuring or breaking the rock. In the few known instances where oil has been produced from quartzites the reservoir space is in the form of fissures or joints. Quartzites are even less important than igneous rocks as reservoir rocks, but there are at least three fields in central Kansas that have produced oil from them.[15]

ACCUMULATION OF OIL AND GAS

Very little, if any, of the oil and gas found in oil pools originated in the reservoir space of the pool. In fact, most of these openings were filled with water before the oil and gas moved in and forced the water out. The cementation of clastic rocks, the modification of limestones and dolomites, which could be accomplished only by circulating waters, the presence of crystals with clean, sharp facets in both clastic rocks and calcareous sediments, the characteristics of the openings in limestones and dolomites, which demonstrate that rock was dissolved by water and carried away, and the connate water found in practically all oil fields testify that, before the oil and gas accumulated, water was at work over a long period.

Even if this convincing evidence were ignored, it would not be possible to believe that the oil and gas originated in the space they now occupy in oil pools, for if that space had been completely packed with organic matter, either plant or animal, and had been converted into petroleum by some natural process, the petroleum would fill but a small fraction of the space required to accommodate the source material.

Oil and gas, being lighter or less dense than the water which occupies most of the openings in the earth's crust, tend to move upward, since that is the direction in which pressure decreases. If they can find a continuous upward route they will reach the surface of the earth, but if, in the course of their journey, they encounter obstacles they cannot penetrate, and which they cannot move around except by moving downward, which is the direction of increase of pressure, migration will cease and the oil and gas will accumulate. Any combination of conditions that will thus preclude upward or lateral movement of oil and gas is a potential trap.

There is some relation between the extent and richness of source beds and the magnitude of oil pools. Of course, no trap can be filled beyond its capacity, but it is usual, rather than uncommon, to find water occupying a part of the trap which might, judging purely from geometrical considerations, have been filled with oil or gas. It has not been possible to establish a quantitative relationship because geologists are still unable to identify source beds definitely; even if they could do so, it is unlikely that they could accurately appraise the original richness of the source beds. In general, however, the "collecting area" tributary to the trap and covering a very substantial area must be regarded as bearing on the magnitude of the accumulation in any pool.

That appreciable quantities of oil can accumulate even though avenues for migration of oil are restricted to the vicinity of the pool is demonstrated by the fields in central Texas in which the permeable formation is a mass of serpentine restricted to the area of the field; the oil must have come in by a lateral movement from the shale beds, with some streaks of sand, that surround the permeable reservoir rock. This is demonstrated also in shoe-string sand fields, such as those of eastern Kansas, where the permeable reservoir rock does not extend laterally into the enclosing shales which, presumably, were the source rock.

TRAPS

Intimate familiarity with trap characteristics is essential, for the search for petroleum and the development and operation of oil and gas pools after they are found depend on the geometry of the trap as well as on the nature of the reservoir and the properties of the contents. Several classifications of traps have been suggested by geologists.[16, 17, 18, 19] The writer prefers Wilson's classification.[16] For details the reader is referred to the publications cited and to the detailed descriptions of individual oil fields in the *Bulletin* and special publications of the American Association of Petroleum Geologists.

The vital elements in all traps for petroleum are barriers that preclude either the lateral or the vertical movement of oil and gas. Any concept of a petroleum trap that does not completely meet this requirement is inadequate and must be corrected before the probable limits of any accumulation of petroleum in the trap, and the geological conditions that will control the amount and distribution of petroleum in the trap, can be satisfactorily established.

The barriers responsible for the original accumulation were provided by reservoir rocks folded or faulted in such a manner as to bar escape from the trap except by downward movement, or by changes in permeability that prevented continued upward or lateral migration. In most pools these barriers that were responsible for the original accumulation may still be detected, but in some instances, where earth movements subsequent to the accumulation of the oil and gas would seem to have left the way clear for the escape of the hydrocarbons from the original trap, they apparently have been replaced by new barriers formed subsequent to the original accumulation but prior to more recent tilting of the strata.

It has been suggested that such barriers may be formed by mineral that has cemented or plugged the openings of the reservoir rock. There can be no doubt that cementation by minerals would prevent the movement of fluids. There are many instances in which the original barriers responsible for the accumulation of oil pools were tightly cemented rocks seemingly continuous with and differing only in permeability from the strata through which the oil had moved and in which it had accumulated. There also are some known instances in which the cementation of the rock adjacent to a pool must have taken place after the accumulation of the oil. The most obvious and extensive occurrences of this type are in the oil pools in the Clinton formation of eastern Ohio, where wells find no water, oil, or gas unless they encounter an oil or gas pool. Today the siliceous strata are indurated to the consistency of a whetstone, yet once there must have been sufficient connected permeability to permit the oil and gas to migrate into and accumulate in the pools where they are now found.

RESERVOIR CONTENTS

Petroleum reservoirs contain gas, oil, and water. Even though the wells may appear to yield oil almost if not quite free from gas and without any trace of water, as in the wells completed early in the life of the Eldorado, Kansas, field, some gas invariably is present, and there are only one or two known fields in which there is any uncertainty concerning the presence of water.

The gas is usually gaseous hydrocarbon, but there may also be present carbon dioxide, nitrogen, hydrogen sulfide, helium, and probably traces of other gases.

The gas may be "free," in which case it fills part of the reservoir to the exclusion of oil. Commonly, such gas-filled parts of the reservoir are the highest parts of the trap in which the oil and gas have accumulated, and the contact between the gas-filled and oil-filled parts of the reservoir is approximately horizontal, but there are numerous exceptions to this general rule. A large part of the gas in all petroleum reservoirs and all of the gas in others is in solution in the oil at the time that the pool is opened by the first well.

The water that exists in the oil- and gas-bearing parts of a petroleum reservoir is called "connate water." It is in no sense a part of the edge or bottom water, but occurs along with the oil and gas throughout the reservoir, even in its uppermost regions. Connate water is important primarily because it reduces the amount of pore space available to oil and gas; it also has effects on their recovery. It is rarely, if ever, uniformly distributed throughout the reservoir, but varies with the rock texture and mineral composition, and with the proximity to edge or bottom water.

EDGE AND BOTTOM WATER

The terms "edge water" and "bottom water" refer to free water in a permeable reservoir rock just below the limits to which a trap is filled with oil and gas. This water can be said to make the "floor" of the trap. The difference between "edge water" and "bottom water" is not in the character of the water but in the manner of occurrence. If the oil or gas fills the entire thickness of the reservoir rock throughout much of the trap, as in Figure 4, the water is considered to enter the trap along the "edge" of the oil-bearing stratum as petroleum is withdrawn and is termed "edge water." If oil or gas does not fill the entire thickness of the reservoir rock throughout much of the trap, as in Figure 5, so that most or all of the wells in the pool will pass from oil-saturated into water-saturated rock if they are drilled deep enough, it is natural to speak of "bottom water."

The contact between the rock that will yield oil with little or no water and the rock that will yield water with little or no oil may be either so abrupt that the line between the oil-filled and the water-filled rock is strikingly sharp, or it may be a gradation rather than a line. In some wells drilled across the oil-water boundary there is an abrupt color change from the brown or black staining due to the oil, to the natural color of the rock itself. In other fields the cores from the water zone contain so much oil that to casual inspection they differ little, if any, from those taken in the "commercial" part of the reservoir rock. Oil can be extracted from such cores with solvents. They have a petroleum odor and oil may even "bleed" in droplets on the surface of the core, but a well completed in such rocks will yield little if any oil. These "water cores" may have a musty odor or a salty taste, and an experienced driller will often correctly surmise that they will yield little if any oil to a well. The

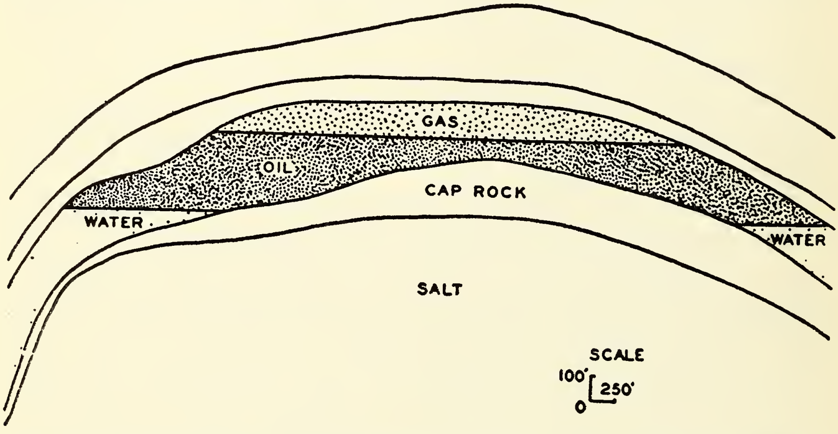

Fig. 4—Cross Section of the Sugarland, Texas, Field Showing Position of Edge Water. (After McCarter and O'Bannon)

only certain test, however, is a production test of the interval in question. Even the electric log, which is, in clastic rocks, quite sensitive to the existence of a high salt-water content, may fail to detect the presence of a prohibitive amount of water. If the reservoir rock is limestone or dolomite, or if it contains fresh rather than salt water, the electric log will rarely indicate the oil-water contact.

The geological significance of a sharp boundary between oil and water is that the trap has not "leaked" or shrunk throughout geologic time and therefore contains all the oil that went into it. If the rocks are heavily stained with oil below the level at which water-free oil can be obtained, it is possible that part of the oil or gas that originally filled the trap escaped through fractures or because the trap was tilted and allowed some of the oil to "spill" after it originally was filled. Another possible explanation is that the regional pressure in an extensive permeable rock, of which the reservoir rock is an integral part, increased after the petroleum accumulated in the trap, and the space occupied by oil and gas was reduced through imposi-

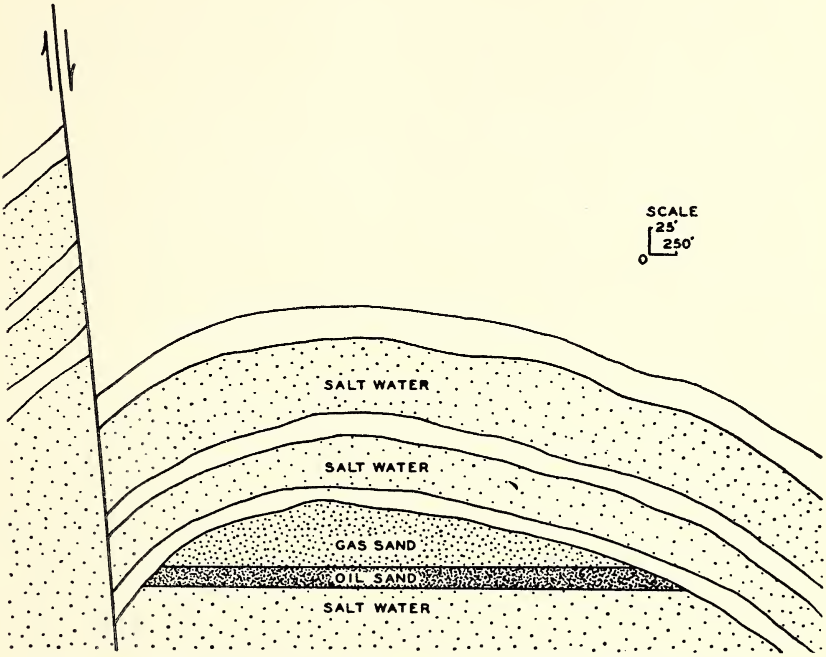

Fig. 5—Cross Section of the Amelia, Texas, Field Showing Oil Pool Underlain by "Bottom Water." (After E. J. Hamner)

tion of pressure. This increased pressure would reduce the volume not only mechanically by squeezing, but by increasing the solubility of gas in oil or of oil in gas.

DETERMINATION OF RESERVOIR CHARACTERISTICS

The essential knowledge relating to a reservoir rock cannot be determined by casual inspection any more than the speed of a horse, the taste of fruit, or the quality of water can be appraised by a glance. The business of recovering oil cannot rest on impressions or guesses. The mineralogy of the rock must be determined, not in general terms but in terms of specified minerals with reasonably close estimates of percentages. If secondary minerals have modified the original nature of the rock, the nature of the alteration and its bearing on porosity and permeability should be known. Particular attention should be given to clay minerals, since among the clay minerals are the culprits that obstruct or, in some instances, prevent the movements of fluids. The mineralogy of the clay minerals is imperfectly known, but in all instances it is at least possible to determine whether the minerals swell when brought into contact with water.

The size distribution of the grains that make up such rocks as sandstones and conglomerates should be determined. As a rule, rocks with a high percentage of grains of uniform size tend to have uniformity of porosity and permeability, and the reverse is true of those which are a heterogeneous assortment of fine, medium, and large grains. The shapes of the grains also are worth noting. There are not as many voids in a pile of bricks as in a pile of baseballs. Such observations on grain shape and size not only permit generalizations concerning porosity and permeability, but also bear on sanding, caving, and other production problems.

Just as mortar can convert a pile of stones into a solid wall, so can the natural mineral cements eliminate much or all of the porosity in rock. Most of the reservoir rocks are cemented to some extent. The nature of the cementing mineral and the extent to which it has occupied what were originally voids between the grains of clastic rocks should be recorded. If the passages between the grains are greatly constricted, space otherwise available for oil or gas is reduced. Unfortunately, this is not the only undesirable effect. The percentage of connate water is, as a rule, higher in very tiny openings than in larger ones, further reducing the reservoir space available for hydrocarbons. Also, water retards the movement of oil in fine openings, so the possible recovery of such oil as is present is impaired. If the cement is carbonate, easily soluble in acid, the permeability near the well bore may be artificially increased to improve both the rate of production and the total recovery.

The thickness of individual beds should be observed. The rock at and close to the bedding planes deserves particularly careful attention to see whether or not there are selvages or skims of clay, mica, or grains of silt size, and whether or not there has been cementation which would "case harden" the rocks at the bedding planes or partings. The reservoir geologist must also be alert to detect the presence of free oil on bedding planes, since such openings, if oil-filled, may increase the oil reserves by a gratifying amount. For the same reason, as much as possible should be learned about joints and fractures. If joints or fractures are abundant and are not filled with mineral cement they may comprise a very important part of the reservoir space. Unfortunately, just as the wind that turns the windmill may shake the fruit from the trees, so may fractures which provide important oil-filled reservoir space also serve as easy channels along which edge water may invade the pool irregularly and reduce the recovery.

Some of the required determinations may be revealed by study of cuttings or small fragments, but for most of them cores are required. If an operator is to recover as much as possible of the oil in a reservoir he will do well to secure cores completely through the reservoir at a number of locations distributed throughout the pool. Generalizations based on a single core are no more valid than the assumption that the performance of a single well will represent what may be expected from all wells in a pool.

The geometry of the reservoir should be determined as precisely as possible. Of course, this cannot be done until enough wells have been drilled completely through it to outline the limits of the oil and gas accumulation, although approximations may be based on a few wells, particularly if seismic work is available that checks with the well data. The configuration of the upper and lower surfaces of the reservoir should be established by maps showing structure contours, and the thickness of the rock by maps with isopachous lines. The assumption that the contact between oil and edge or bottom water is a horizontal plane is rarely safe and may lead to very serious mistakes. The contact must be conclusively established in a number of wells.

The amount of reservoir space available depends on the volume of the reservoir rock and the amount of effective porosity. Satisfactory determinations of porosity can be made from cores or even from comparatively small fragments. Many determinations of representative samples distributed both vertically and laterally throughout the reservoir bed are needed. The porosities of the carbonate rocks are particularly liable to have a broad range. The technique described by Imbt[20] for injecting plastic into the rock and then dissolving the rock substance so that a cast of the porosity remains for inspection should greatly improve understanding of the oil storage space in such rocks and should also permit accurate determination of the available reservoir space in selected samples.

For the permeability determinations, which now are considered essential to effective reservoir engineering, cores are indispensable; these cores must be large enough to permit plugs an inch, and preferably more, in length to be cut from them in a direction parallel to the bedding of the rock.

Free or undissolved gas in the reservoir is revealed by well behaviors, drill-stem tests, electric logs, and cores. The only criterion that is completely diagnostic is well behavior. Drill-stem tests may indicate free gas when actually a water block has been formed which prevents oil from entering the hole. If the test is extended over a period of some hours such a condition should be disclosed, but, as a rule, drill-stem tests are of short duration. Electric logs, in their present stage of development, are no more dependable than their empirical interpretation. Two students may reach equally positive but otherwise quite different interpretations. Cores containing light oil may lose that oil so completely while they are being cut and withdrawn from the well that little trace of its presence is detectable. Also, many reservoir rocks that are stained with oil will yield only free gas to a well.

The connate water present in some amount in most, and probably in all, petroleum reservoirs can be detected and measured only in cores. The technique for securing cores that will yield satisfactory measurements has been given careful consideration,[21,22] and great pains must be taken to make reasonably accurate determinations possible. Many determinations of connate water, distributed both laterally and vertically throughout the reservoir rock, are required to furnish a real understanding of the amount and distribution of the water.

The reservoir space not occupied by free gas or by connate water in a newly discovered pool is occupied by oil. "Nature abhors a vacuum." It is not imaginable that there is empty space surrounded by and in connection with gas, oil, or water under pressure. The amount of oil present in any reservoir must be determined by difference. The total space, that filled with free gas, and that occupied by connate water can be approximately determined if cores, measurements, and observations are adequate.

DISCOVERY OF PETROLEUM RESERVOIRS

Throughout the early years of the petroleum industry those who drilled for oil depended on the appearance of substantial quantities of oil, either in the well bore or actually flowing from it at the surface of the ground, to inform them they had penetrated an oil reservoir. The manner in which the drilling bit penetrated the rock, with, perhaps, some additional information from the rock "cuttings" recovered from the hole, was used to tell them whether the reservoir rock was thick or thin. The term "gusher" was a familiar and common word, and photographs or drawings of wells with derricks half hidden by a black cloud of oil that towered above the crown block were commonplace in the literature and on stock prospectuses. There was no "discovery" unless oil rose for some distance in the well bore; all too frequently it was made emphatically apparent by thousands of barrels of oil that blackened the landscape before the well was brought under control.

There were, of course, some disappointments. Oil or gas might enter the hole with such pressure as to throw the drilling tools through the derrick and roar from the well-head impressively for hours or even days, after which the flow would abruptly cease and all efforts to re-establish entry of oil or gas in important quantity into the well would fail. The driller would conclude that he had encountered a "pocket" of oil or of gas and would either abandon the well or drill ahead, the decision depending on his finances, the condition of the hole after the convulsive entry of oil or gas, and his ideas concerning possibilities at greater depth. In many instances the diagnosis that the drill had encountered a "pocket" was probably essentially correct. It had penetrated an oil- or gas-filled fissure or permeable rock in an isolated body of small dimensions. In other instances, however, he turned his back on an oil pool of commercial importance which was later rediscovered and developed by more skillful or more fortunate operators.

Cable tools were used exclusively in the early days of exploration. The assumption that if oil or gas was encountered in a well drilled with such tools its presence would unquestionably be recognized is, even today, held by many. This is because only a little water is used with cable tools—just enough to keep the tools cool and to make a thin slush of the rock cuttings—so the pressure inside the hole is far below that which commonly exists in permeable rocks containing free liquid or gas. However, if the pressure in the reservoir rock should be very low the presence of oil might conceivably be missed. If the reservoir rock contained a large proportion of clay minerals that would swell when brought in contact with fresh water, the rock close to the hole might quickly be made impermeable. Also, under some conditions it is desirable to drill with water standing high in the hole. When this is done it might be possible to drill through a low-pressure reservoir without detecting the existence of oil.

Cable tools have now been replaced by rotary tools in all areas where the formations are soft, where high pressures are anticipated, where many water-bearing strata must be penetrated, or where great depth must be attained. They are used in preference to cable tools in many fields where conditions offer no particular handicap to the cable tools but where the greater speed with which the rotary tools can complete a well is considered important. Rotary tools have played a very important part in the development of the petroleum resources of the world, but the speed and certainty of making hole they brought with them were, for many years, to some extent offset by uncertainty concerning the nature of the formations they penetrated, and whether or not the drill had gone through petroleum-bearing reservoirs. This was so true that dry exploratory wells drilled years ago with rotary tools are not looked on now as condemning a prospect if there is geological reason for considering that prospect favorable. Even today the handicaps to discovery have not been completely overcome.

When the hole is full of mud-laden drilling fluid, as it should be when a well is drilled with rotary tools, the pressure of the mud column exceeds the pressure in most of the petroleum reservoirs that may be encountered. The drilling fluid tends to hold back, or to drive back into the permeable formation, oil and gas that would enter the hole if the pressure differential were reversed, so that little or no "showing" of oil or gas may appear in the drilling fluid. Ingenious methods to detect the presence of oil and gas in the hole, and to determine accurately the depth, thickness, and nature of the stratum in which they occur, have been developed, but there must be further improvements before the danger of overlooking the existence of potentially important petroleum reservoirs is completely overcome.

The old maxim of the explorer that "the best evidence of oil is oil" still holds. The most satisfactory methods for detecting the presence of an oil reservoir are those that result in its being actually seen, smelled, or tasted. The oldest of these methods is "full-hole" coring, which consists in cutting and removing from the well a solid core or column two, three, four, or more inches in diameter of the rock penetrated by the core bit. To expedite and lower the cost of coring, methods of sampling or taking small cores from the sides of a drill hole have been developed. Such samples are secured at depths where cuttings, drilling characteristics, or the patterns on electrical or radioactive logs suggest reservoir rock may be present, or they may even be taken at random.

Solvents for oil, such as chloroform, ether, carbon tetrachloride, and acetone have long been used on cores and cuttings from wells to detect the presence of oil that might not be manifested by color or odor. More recently, ultraviolet or "black" light has been employed for this same purpose, since oil, even in minute quantities, betrays its presence through characteristic fluorescence. Ultraviolet light is also used to detect the existence of traces of oil in drilling mud. Methods of analysis have also been developed that will reveal the presence of traces of gas in drilling mud.

The method by which an "electric log" of a bore hole is secured has unquestionably contributed more to the discovery of petroleum in wells drilled with rotary tools than has any other aid; in addition, it is now an indispensable geological tool in many areas. Oil, gas, fresh water, and rocks of certain types may be indicated by relatively high resistance to the passage of electrical current. Permeable rocks may be indicated by the contrast of the so-called "self-potential."

Radioactive logs are used to supplement the information secured from electric logs, or to secure information not otherwise obtainable. The electric log can be secured only in an uncased hole, while the rocks are in contact with the drilling fluid in the hole, whereas the gamma rays that are responsible for radioactive records will penetrate the steel casing. The radioactive characteristics recorded are controlled by the existence of specific minerals in the formations and therefore are primarily useful to increase knowledge concerning the distribution of rocks of different types. Whether or not such rocks are sufficiently likely to contain petroleum to justify testing rests on geological inference.

If there is doubt that petroleum has actually been encountered, or as to which of several oil-bearing strata in a single hole should be opened for production, drill-stem tests may be used as a preliminary to completing the well. They may be run in either a cased or an uncased hole.

All of these methods, coring, testing, and logging, are employed extensively in the search for oil and gas. The instruments and techniques are by no means perfect, and erroneous interpretations are sometimes made. However, they are being continuously improved. Directly and indirectly, they must be credited with responsibility for the discovery of many important pools.

OIL FIELDS

A distinction has been made between an "oil pool" and an "oil field." According to Lahee,[23] "A pool . . . is an underground accumulation of petroleum in a single and separate natural reservoir . . . . characterized by a single pressure system so that production of petroleum from one part of the pool affects the reservoir pressure throughout its extent. In all directions a pool is so bounded by geologic barriers that it is effectively separated from any other pools that may be present."

According to the same author, "A field may be a single pool or it may consist of two or more pools all on or related to the same geologic structure. Where there is more than one pool in the same field, the several pools are separated from one another through geologic causes . . . . the pools may occur at several horizons of different geologic age separated by relatively impervious strata and in such cases they may directly, or only partly, overlap one another in a horizontal sense; or they may not overlap at all."

An oil or gas "pool" then is the oil or gas in a single reservoir. A field may include more than one reservoir. The provision that the several reservoirs in a single field should be "on or related to the same geologic structure"[23] is not strictly followed in common usage. If two reservoirs overlap horizontally, or even if they do not but are in close proximity, as may occur when reservoirs in monoclinal or in flat-lying rocks are confined by impermeable rock rather than by deformation of the strata, the separate reservoirs are often considered parts of the same field.

There is but one valid criterion by which single reservoirs may be recognized as such. There must be "pressure connection," which means continuous or interconnected permeability throughout the reservoir, so that a change in the pressure in one well or in one part of the reservoir will ultimately affect the entire reservoir. For practical purposes, this adjustment must take place and be detectable in days, months or, at most, a year or two. There is reason to believe that some of the relationships that have been observed in oil fields required geologic rather than finite time for their establishment. A permeability connection that would permit readjustment of pressure in a thousand years probably would not be detectable; it certainly would not need to be considered by the petroleum engineer. To him such a connection would be a barrier separating the oil accumulation into pools in two distinct reservoirs.

Single reservoirs or "pools" commonly are in strata or layers of rock such as sandstone or limestone that are laterally continuous and fairly uniform in character throughout the extent of the pool. If they do change in nature the changes are usually progressive and gradual rather than abrupt. The characteristics are well manifested in such fields as Burbank, Oklahoma,[24] and Mexia, Texas.[25] The reservoir rock in these fields may be broken by streaks or layers of impervious shale, but these barriers are not traceable from well to well throughout the field.

However, single reservoirs may also include two or more permeable layers or strata that are separated by layers of impermeable rocks. Many fields are known where two or more such oil-bearing strata, separated by thick bodies of impermeable rock, have oil-water contacts at the same datum with respect to sea level. An excellent example is the Crescent field of Oklahoma. (Figure 6). Where this condition is found there can be no doubt that there was intercommunication and adjustment, presumably along fissures or fractures, between the separate oil-bearing strata at some time in the life of the pool. Whether or not the avenues of communication still function can be determined only by pressure measurements during the life of the field, or by observed interference between wells that have been bottomed in separate strata. In many instances it will be found that pressure adjustment no longer will take place at a measurable rate; should such adjustment occur the several oil-bearing strata are but parts of a single reservoir.

Multiple reservoirs may occur in a laterally continuous rock stratum that is broken into compartments by impermeable barriers formed by local cementation of the reservoir rock. Fortunately, such occurrences are relatively rare. More commonly there may be two or more closely adjacent pools in permeable rocks that occupy similar or identical positions with respect to overlying and underlying strata, but which are locally replaced by shale or impermeable limestone or dolomite. However, in most of the fields containing more than one reservoir the reservoirs are separated, vertically, by thicknesses ranging from tens to thousands of feet of barren strata, and both the reservoir rocks and the oil in the different "pools" may have wide ranges in properties.

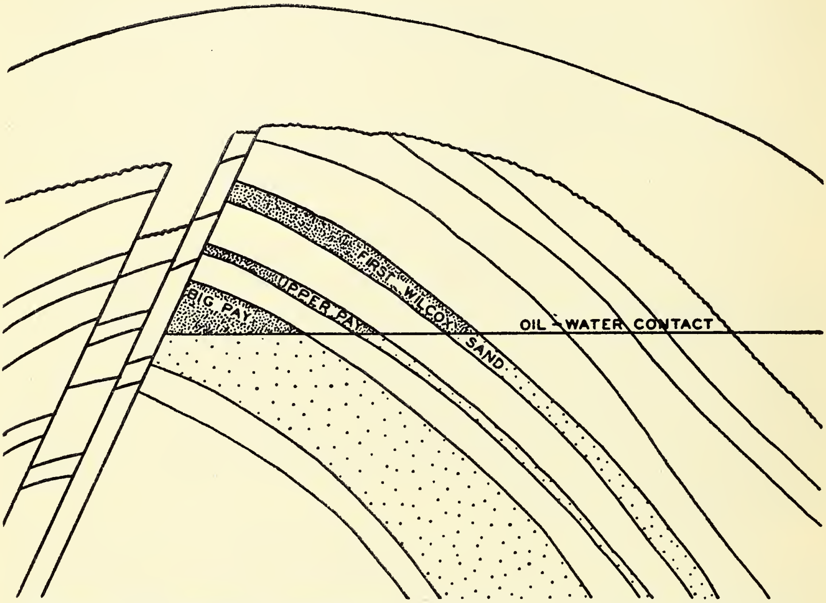

Fig. 6—Cross Section of Crescent, Oklahoma, Field Showing Three Reservoir Rocks with Common Water Level. (After Clark, Tomlinson and Royds)

On the other hand, there are many fields in which the reservoir rocks are comparatively thin and are separated by impervious layers which also are thin. In extreme cases the field may comprise a great number of porous strata, each only a few inches thick, which are sandwiched between thin layers of shale. In some instances, a thick oil-bearing sandstone or limestone may be divided into oil-bearing layers by impermeable streaks or beds parallel to the upper and lower limits of the reservoir rock. Such divisions, particularly if they are due to cementation or to the siltiness or dirtiness of the reservoir rock, cannot be detected unless the complete thickness of the reservoir rock is cored and core recovery is perfect. In order to secure an adequate yield of oil from individual wells it is often necessary in such cases to open several or many of these oil-bearing strata into the same well.

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Chapter IV

CHARACTERISTICS OF RESERVOIR FLUIDS

THE FLUIDS IN THE RESERVOIR

Efficient recovery of petroleum from underground reservoirs requires not only a thorough and intimate knowledge of the specific physical features of each particular reservoir, but also a complete understanding of the characteristics and behavior of its contained fluids. These fluids are water, oil, and gas. Although usually a brine, the connate water that occupies a part of the pore space in almost all petroleum reservoirs does not differ materially from water of similar composition at the surface; it is important chiefly because it decreases the amount of space available for occupancy by oil and gas and because, through its effect on certain materials within the producing formation, it may modify the sizes and shapes of the interstitial pore spaces through which the oil and gas must flow. The properties of oil and gas, on the other hand, may be far different at the pressure and temperature of the reservoir than at the surface.

PHASE BEHAVIOR

The States of Matter

Under ordinary conditions of observation at atmospheric pressure and temperature, three states of matter are recognizable: solid, liquid, and gas. They are readily distinguishable by such elementary features as the tendency of a solid to retain a definite shape and to resist deformation, whereas liquid and gas yield readily to any imposed force, each modifying its shape to fit that of a confining vessel. A liquid is usually readily distinguishable from a gas in its ability to establish a surface in a partially filled container; a gas will completely fill any confining space.

Although petroleum may exist in solid forms, these solids cannot be recovered except by mining operations. This chapter is concerned primarily with petroleum as a fluid, a material that can flow into a well bore from an underground reservoir, and in those characteristics that affect its recovery.

Petroleum a Complex Mixture

Petroleum is a tremendously complex substance. It is preponderantly a mixture of hydrocarbons, but frequently it contains carbon dioxide, nitrogen, and hydrogen sulfide in significant proportions as either dissolved or free gases, together with heavier sulfur-, nitrogen-, and oxygen-bearing compounds. The liquid crude oil produced at the surface may be predominantly paraffinic, naphthenic, or aromatic; it may contain a large proportion of asphaltic materials, or almost none. The chemical composition controls not only the products recovered or manufactured from a petroleum, but its physical characteristics and behavior as a fluid.

The lightest hydrocarbon is methane; it contains only one carbon atom in each molecule. It boils at atmospheric pressure at –258.5°F. and when pure cannot be liquefied at a temperature above –116°F. It is the dominant constituent of most natural gas. As the number of carbon atoms in the molecule increases, the hydrocarbons become progressively denser and their boiling points progressively higher, so that they grade from gases through liquids and finally to solids at normal temperature. For example, ethane, which has two carbon atoms in each molecule, boils at –127.5°F.; propane, with three carbon atoms, at –44°F.; iso-butane and normal butane, with four carbon atoms, at 10°F. and 31°F.; and normal octane, with eight carbon atoms, at 258°F. The lighter hydrocarbons in petroleum can be separated and identified individually, but the number of individual hydrocarbons containing more than about eight to ten carbon atoms is so great that they can be identified only by groups or classes.

These materials find their way into commerce as different products. Methane is sold as natural gas; ethane is usually included in the natural gas along with methane, but is sometimes separated for use in chemical manufacture; propane and butanes are frequently separated and sold as liquefied petroleum gas (LPG or bottled gas), and, along with pentane, hexanes, and some heavier materials, are stripped from gas and sold as natural gasoline. Heavier materials are commonly separated by boiling range into such products as gasoline, kerosene, diesel fuel, heating oils, lubricating oils, and residual fuels. Asphalts and waxes are sold as solids or semi-solids.

If the petroleum in a reservoir consists predominantly of materials that are normally liquid, it is produced in the form commonly recognized as crude oil. If it is predominantly methane, with only slight or moderate amounts of heavier material, it is produced in the form of natural gas. If the gas recovered at the surface is produced from an oil well, it is commonly called casinghead gas. If it issues from a gas well, no particular designation other than natural gas is commonly used, except that if the gas is accompanied by no liquid at all it is sometimes called dry gas, and if accompanied by a small or moderate amount of liquid separated at the surface it is sometimes called wet gas. Even if a gas is "dry," it may still contain in the gaseous state heavier hydrocarbons that may be stripped from the gas in an absorption- or refrigeration-type natural gasoline plant. Natural gasoline is commonly recovered from both casinghead gas from oil wells and natural gas from gas wells.

The petroleum in a reservoir may represent any degree between the extremes of predominantly gaseous hydrocarbons or predominantly liquid hydrocarbons. The material may be present as two phases, liquid and gas, or as a single phase, all reservoir liquid or all reservoir gas. The state of the petroleum in the reservoir cannot always be inferred from the character of the material produced at the surface, for both liquid and gas are usually obtained at the surface regardless of whether the well is producing only reservoir liquid, only reservoir gas, or a mixture of both.

The reservoir state of material produced from shallow pools of moderate reservoir pressure is usually readily recognizable as being obviously reservoir liquid, reservoir gas, or a mixture of the two. As wells are drilled deeper, encountering reservoirs at higher pressures and temperatures, the distinction between the phases becomes less sharp and their compositions tend to become more alike, so that in many cases extensive experimental tests are required to characterize properly the material in a deep reservoir. It is very important to determine whether the oil and gas produced by a well exist in the reservoir as a single-phase liquid or gas, or whether they represent a mixture of two reservoir phases.

Phase Diagrams

One method of portraying the state of a mixture is by use of a phase diagram. A phase diagram is a plot that shows the state under various conditions. Several types of diagrams are employed for this purpose, but one that is particularly useful in describing the character of petroleum in a reservoir is a diagram that shows the effects of pressure and temperature on the number of phases present.

Because petroleum is a mixture of thousands of different materials, some gaseous, some liquid, and some solid when isolated in the pure state at atmospheric conditions, its physical behavior differs in many important respects from that of a single pure substance. These mixed materials dissolve in each other to form homogeneous liquid- or gas-phase solutions, and the state of the petroleum is dependent on the character of these solutions.

Figure 7 shows the contrast between a pure material and petroleum. Figure 7-A is a phase diagram for a pure substance, and Figure 7-B is an idealized phase diagram for a petroleum. For a pure substance there is a single equilibrium line representing the vapor pressure of the material as a function of temperature; at the pressure and temperature indicated by the line, liquid and vapor can coexist at equilibrium, but at any other condition the material is either all liquid or all gas. The vapor-pressure line terminates at a critical point, labeled C in the diagram. At temperatures higher than the critical only a single fluid phase can exist, regardless of the pressure. In the case of a pure substance the single fluid phase at temperatures higher than the critical is commonly considered to be gaseous, and it is commonly stated that a material cannot be liquefied at temperatures above the critical.

In the case of petroleum this simple behavior no longer holds.

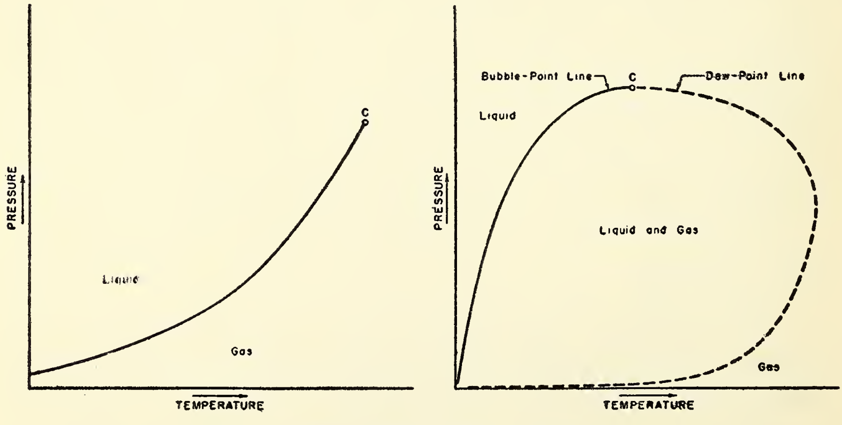


FIG. 7—Illustrative Phase Diagrams

FIG. 7-A—Pure Material FIG. 7-B—Petroleum

Instead of a single-line relationship between pressure and temperature along which liquid and gas can coexist, there is a broad region of temperature and pressure within which liquid and gas can both be present at equilibrium. This region is bounded on one side by a *bubble-point* line and on the other by a *dew-point* line, these two lines joining at a critical point. At the critical temperature and pressure the composition and all other properties of the gas and liquid become identical. Outside of the region bounded by the bubble-point and dew-point lines only a single homogeneous fluid phase can exist. Of particular significance is the fact that in the case of petroleum the critical temperature is no longer the maximum temperature at which a liquid can exist; liquid may exist within a large region of temperature and pressure enclosed by the dew-point line above the critical temperature. This condition leads to peculiar phenomena that become of great importance in the production of certain types of petroleum reservoirs.

Reservoir State

The bubble-point line and the dew-point line are called phase boundaries. They identify the pressure and temperature at which a change in state will occur. For example, at a point in the upper left-hand portion of the diagram in Figure 7-B, at a temperature below the critical and at a pressure above the bubble-point line, the petroleum will all be in a single homogeneous phase. Since this phase can exist only when it is confined under pressure it cannot be identified readily as either liquid or gas. If the pressure is reduced the petroleum will continue to exist as a single homogeneous phase until the bubble-point pressure is reached. At that pressure the material will begin to change from a single phase to two phases, the first evidence being the formation of a bubble of gas. At pressures lower than the bubble point the material will continue to remain as two phases until the dew-point pressure is reached. It will then become a single gas phase. While two phases are present they are identifiable as liquid and gas because the liquid has a surface.

Conversely, if the petroleum is at a temperature higher than the critical and at a pressure higher than the dew-point line in Figure 7-B, it will again be a single homogeneous phase. If the temperature, although higher than the critical, is less than the highest temperature enclosed by the dew-point curve, and if the pressure is reduced while the temperature is maintained constant, the material will continue to exist as a single phase until the dew-point pressure is reached. At that pressure a second phase will begin to form, the first evidence being the formation of a droplet of liquid.

The state of the petroleum in a reservoir is identified by the relation of its dew-point and bubble-point pressures and temperatures to the reservoir temperature and pressure. If a single-phase reservoir material is not at its dew-point or bubble-point temperature and pressure within the reservoir, the state of the material cannot be defined except arbitrarily. However, the convention that has been adopted and which has the support of common usage is that the material is called *liquid* if at reservoir temperature a reduction of pressure will cause a bubble of gas to appear when the phase-boundary pressure is reached, and the material is called *gas* if at reservoir temperature a reduction of pressure will cause liquid to form when the phase-boundary pressure is reached.

This convention is important in several respects. It makes it possible to predict from identification of the reservoir state whether gas will be evolved from solution or whether liquid will condense within the reservoir if the pressure is reduced. It is also necessary to the definition of crude oil and natural gas for such purposes as contracts and state regulations governing production.

RESERVOIR OIL

The behavior of petroleum in the reservoir may be more readily understood by separate consideration of the extremes represented, on the one hand, by a preponderance of material that will be produced in the form of liquid crude oil accompanied by a small or moderate amount of natural gas, and, on the other hand, by a preponderance of material that will be produced in the form of gas accompanied by no liquid or by only a moderate amount of material recoverable as liquid under normal surface conditions.

In the case of the ordinary liquid crude oil the reservoir state is presumed to be obviously liquid, and it is not necessary to consider the entire phase diagram to delineate the pertinent facts concerning its behavior. The temperature region of interest is bounded by the reservoir temperature as a maximum and the surface temperature as a minimum. Similarly, the pressure region of interest is that lying between the original reservoir pressure and atmospheric pressure. In the case of the typical liquid crude oil the dew-point line is of no interest, as the liquid contains a high proportion of components of such low volatility that extremely high vacuum would be required to achieve complete vaporization within the temperature region involved in production. Also, the critical temperature of a normal crude oil would be so much higher than the reservoir temperature that the phase region above the critical temperature would be of no interest in production operations. This high-temperature phase region cannot even be investigated experimentally because of cracking of the heavier components of the oil at the temperatures that would be involved.

The pertinent behavior of the typical liquid crude oil may be reduced, therefore, to consideration of the properties of the reservoir oil and its dissolved gas and of the physical changes that may take place in the reservoir or at the surface during the course of production.

PERTINENT PROPERTIES OF TYPICAL RESERVOIR OIL

The important properties of the reservoir oil are its composition, including, particularly, the amount of volatile material that may escape to become gas; the changes in state that the fluid may undergo, including specifically the amount of gas that will be released from solution at any pressure and temperature encountered during production; the pressure at which dissolved gas will first escape; the shrinkage of the reservoir oil caused by escape of dissolved gas; and those properties of the oil and gas phases that in any manner affect their movements within the reservoir.

Sampling of Reservoir Oil

It is common practice to determine experimentally the important properties of a particular oil by laboratory tests of a representative sample of the reservoir liquid. Samples of reservoir oil can be obtained most conveniently through the use of a subsurface sampling device, which is lowered on a wire line to the bottom of an oil well and procures under pressure a sample of the oil and its dissolved gas. Various types of such sampling devices are in use, and the taking of subsurface samples is common practice. Some investigators prefer to obtain samples representative of reservoir oil by taking from a surface separator samples of the produced gas and oil and combining them in the produced proportions. Either method is suitable, local conditions usually influencing the choice. These samples, regardless of their source, are compressed to produce a homogeneous fluid phase and are heated to reservoir temperature, and the pertinent determinations are made under simulated reservoir conditions. The factors determined, their significance, and the experimental procedures involved are outlined in the following discussion.

Composition

It is customary to determine by a process of fractional distillation at low temperature the amount of each individual volatile hydrocarbon dissolved in the reservoir oil through normal pentane, and to determine by fractional distillation at higher temperature the amounts of those heavier hydrocarbons that may escape with the dissolved gas to a significant degree during production. Since hydrocarbons containing ten or more carbon atoms have very low volatility at normal temperatures and pressures, the higher temperature distillation is usually not carried beyond the boiling point of the ten-carbon-atom hydrocarbon, decane. There are a large number of individual hydrocarbons containing from six to ten carbon atoms in each molecule, and their boiling points are so close together that it is not usually practical to separate and identify each individually by a fractional distillation process. The hydrocarbons from hexanes on are therefore usually identified in groups according to a boiling-point range.

It is customary to determine, in addition to the amounts of volatile materials, certain properties of the remaining oil from which the volatile materials have been removed. The density, the average molecular weight, and the viscosity are frequently determined.

It is important to know the composition of the reservoir oil because it is possible to calculate from the composition the changes in certain properties of the oil and its released dissolved gas that will result from changes of pressure or temperature during the course of production.

Saturation Pressure

The volatile materials dissolved in the reservoir oil have a natural tendency to escape from solution to assume the form of gas. They are kept in solution by the pressure prevailing in the reservoir. The pressure that is just sufficient at the prevailing temperature to prevent any escape of dissolved materials is commonly called the *saturation pressure* or the *bubble-point pressure.* If the imposed pressure is greater than the saturation pressure, no dissolved volatile materials can escape from solution; if the imposed pressure is reduced to a value lower than the saturation pressure, dissolved materials leave the oil and become gas. The saturation pressure is determined experimentally by varying the pressure on a confined sample of reservoir oil and determining the point at which the first bubble of gas escapes from the solution. This point is usually identified by a sudden increase of volume of the material as the pressure is reduced. It should be noted that the saturation or bubble-point pressure of a reservoir oil is the same phase-boundary pressure referred to in connection with Figure 7-B.

The saturation pressure is important because it is the reservoir pressure below which dissolved gas will be liberated from the oil and will begin to occupy reservoir space formerly filled with oil.

The amount of gas initially associated with the oil in a reservoir is not always sufficient to saturate the oil at the prevailing temperature and pressure; if it is insufficient to do so, all of the gas will be dissolved in the oil and only a single liquid phase will exist within the reservoir. In such an instance the oil will be undersaturated, in that the pressure exerted by the dissolved volatile materials in their attempt to escape from solution will be less than the reservoir pressure, and more gas could be held in solution in the reservoir oil if such additional gas were present. Many reservoirs are found to contain undersaturated oil, an outstanding example being the East Texas field. The original average reservoir pressure in that field was 1,620 pounds per square inch, but the saturation pressure of the oil at reservoir temperature averaged only 750 pounds per square inch.

If the amount of gas initially present with the crude oil exceeds the amount that can be held in solution at reservoir temperature and pressure, the excess gas exists as associated "free gas," occupying, usually, the upper part of the reservoir as a gas cap. The designation "free" is employed to indicate that this excess gas is not dissolved in the liquid oil but exists separately as a distinct gas phase. When excess gas is present the reservoir oil in immediate contact with the free gas is usually saturated, but oil further down dip in the reservoir is under greater pressure and is not usually saturated at its prevailing reservoir pressure. Pools have been encountered in which most of the oil was quite undersaturated with gas even though free gas was present in the upper part of the reservoir and there was no physical barrier between the gas and the oil.

Since the saturation pressure may or may not be equal to the original reservoir pressure in a pool, and since it has been found that the oil in different parts of the same reservoir may differ in composition and saturation pressure, experimental sampling of the oil from a representative number of wells in each reservoir is necessary for proper determination of the characteristics of the reservoir oil.

Dissolved Gas

A certain amount of confusion exists regarding gas dissolved in crude oil. This confusion is a natural result of concepts based primarily on the behavior of pure substances and simple mixtures, coupled with failure to modify the concepts to fit the behavior of such a complex substance as petroleum.

The gas dissolved in the liquid crude oil phase in the reservoir is nothing but the volatile components. While in solution it is an indistinguishable part of the complex, but homogeneous, liquid phase. So long as this gas remains dissolved it imparts certain properties to the liquid and is as much a part thereof as is any other part of the liquid. The dissolved gas can be identified as gas only by a process of separation. Confusion arises from the fact that the amount of dissolved gas that may be separated from a liquid crude oil depends not only on the composition but also on the manner by which separation is achieved.

This behavior is different from that of the solution of a pure gaseous material in a single-component or non-volatile liquid, as, for example, the solution of carbon dioxide in water. The solubility of carbon dioxide in pure water at any particular pressure and temperature may be precisely stated as an invariant quantity dependent only on the temperature and pressure; it is the same whether one measures the amount of gaseous carbon dioxide that may be forced into the water at the specified conditions, or measures the amount of carbon dioxide removable from water previously saturated at the specified conditions.

It is possible to determine from experimental measurements the amount of gas liberated from or separated from a crude oil under a specified sequence of operations, but the amount liberated to any final temperature and pressure depends upon the separation procedure employed. Thus, the amount of gas dissolved in a crude oil cannot be stated as a single quantity but only in terms of a liberation procedure. In spite of this limitation, the "dissolved gas" is a useful concept when properly employed to describe qualitatively the amount of volatile material present in an oil or that will escape from an oil under certain known conditions.

Flash or Equilibrium Vaporization—When a sample of a typical reservoir oil is placed in a closed vessel of variable volume and heated to reservoir temperature, and the pressure is systematically reduced from reservoir pressure to atmospheric pressure while equilibrium is continuously maintained between the gas and liquid phases, a progressively increasing amount of gas is released from the liquid phase. This gas phase contains not only hydrocarbons from methane through butanes, but also pentanes, hexanes, and heavier materials, including even traces of hydrocarbons containing ten or more carbon atoms. As the pressure is reduced, the gas phase increases in quantity at the expense of the liquid phase; the gas phase grows in volume, and the liquid phase shrinks. Such a process of gas liberation, in which equilibrium is continuously maintained between the two phases, is commonly called a *flash* vaporization process. Maintenance of equilibrium means that each kind of material present in the mixture distributes itself between the gas and liquid phases in accordance with the prevailing pressure and temperature in such proportions as to preserve continuously an equal tendency to escape from either phase. By appropriate measurements one may determine by such a process the volume and composition of the gas liberated to any reduced pressure, and the volume and composition of the residual liquid. Corresponding charts or tables may then be prepared showing the amount of "dissolved gas" liberated by flash vaporization from the particular oil at a specified temperature. Because the volatility of each of the hydrocarbons comprising the crude oil depends on the temperature, both the amount and composition of the liberated gas would be different if the liberation were effected at a different temperature.

Differential Liberation—When the experimental process just described is modified so that after each stepwise reduction of pressure the incremental quantity of liberated gas is removed from the system instead of remaining in equilibrium with the residual oil, the process is that of *differential* liberation. The amount and composition of the gas liberated to any pressure, and the amount and composition of the residual crude oil are different from the results obtained by the equilibrium vaporization process.

Gas Liberation in the Reservoir—It is common practice to carry out experimentally both types of liberation process on samples of reservoir oil. The process of gas liberation that occurs within the reservoir is not exactly represented by either flash or differential liberation. When the reservoir pressure is reduced below the saturation pressure of the oil the gas that first escapes from solution in the reservoir remains behind instead of flowing with the oil. At a later stage of pressure reduction gas may escape from the reservoir more readily than does the oil, approximating conditions of differential liberation. Fortunately, the differences between differential and flash vaporization are usually minor at moderate to high pressure, becoming large only at low pressure, so that it is usually possible to approximate from either type of measurement the amount of reservoir gas liberated during early stages of depletion of a pool, and to use approximations based on differential liberation for later stages of depletion should the reservoir be so operated as to reach low pressure.

Surface Separation—After oil and gas have entered a well bore, the mixing that occurs during their travel through the tubing and flow line to a separator is usually sufficient to bring about equilibrium between the phases. Thus, the separation of gas and oil in a surface separator may usually be represented with sufficient accuracy for most engineering purposes by a flash vaporization process at the temperature and pressure of final separation. The oil leaving the separator undergoes a second or third flash liberation process in flowing through an intermediate separator or to the stock tank. It is the composition of the material entering the well bore and the effects of these separations that together fix the shrinkage of the oil in passing from the reservoir to the surface, the density of the residual crude oil, and the produced gas-oil ratio.

Formation Volume Factor

It is a customary procedure to measure in a stock tank the volume of oil produced from a well or lease, to determine the density, and from the density, with the aid of correction factors, to correct the measured oil volume to what it would be if the oil in the tank were gauged at a standard temperature of 60°F. The density is also corrected to 60°F.; in the United States it is usually reported in terms of a specific gravity scale as degrees API.

The reservoir temperature in most oil and gas fields is higher than 60°F., often being as much as 200°F. in deep reservoirs. During the course of production, the shrinkage of the oil that results from escape of some of the volatile components as liberated dissolved gas, and a contraction of volume caused by the temperature reduction on removal of the oil from the reservoir to the stock tank together bring about an over-all reduction of the volume of the liquid oil phase. These effects are usually determined experimentally and grouped together as the shrinkage. The *shrinkage factor* is commonly used to designate the fractional volume of oil in a stock tank, corrected to 60°F., obtainable from a barrel of reservoir oil measured at the original reservoir temperature and pressure with all of its volatile components still in solution. The *formation volume factor* is commonly used to designate the converse, the volume of reservoir oil required to yield a barrel of stock-tank oil at 60°F.

These factors are essential for accurate estimation of the recoverable oil content of a reservoir and for certain calculations, explained in later chapters, that are required for analysis of the behavior of an oil reservoir. Since the shrinkage is dependent to a large extent on the amount of dissolved material lost from the oil in the form of gas, it is influenced by the separation procedure employed. Accurate determination of the applicable shrinkage factor requires, therefore, determinations as nearly as possible representative of the specific conditions encountered by the oil during the course of production for each particular pool.

Calculation of Properties

If the composition and the density of the reservoir oil are determined, it is possible to calculate from the known behavior of hydrocarbon mixtures many of the properties of the reservoir oil. Among the items that may be calculated are the saturation pressure, the amount and composition of the dissolved gas that will be liberated from the oil by either an equilibrium or a differential separation process, the shrinkage of the oil, and the gravity of the remaining oil. Such calculations are particularly useful for determination of the effects of various surface separation conditions on the volume and composition of the separated gas and the gravity and residual volume of the oil recovered in the stock tank.

Properties That Change in the Reservoir During Production

The physical character of the oil in a reservoir is determined by its composition and environment. Of particular importance to oil recovery are the changes that may take place within the reservoir during production. The environment changes through decline of reservoir pressure, and the composition of the reservoir oil changes because dissolved volatile materials are liberated from the liquid to become gas. The dissolved gas components affect particularly the density, the volume, the viscosity, and the interfacial tensions of the liquid reservoir oil, each of which has an important effect on oil recovery.

The changes are usually determined by laboratory measurements carried out at reservoir temperature on representative samples of reservoir liquid. The measurements are made by compressing the reservoir liquid sample to a pressure above the original reservoir pressure and repeating the determinations of the properties of the liquid as the pressure is systematically reduced and gas is released from solution. The following sections outline the manner in which these properties change in the reservoir as the pressure declines.

Volume and Density—So long as the reservoir oil remains completely in the liquid state its volume and density are relatively insensitive to change of pressure, the liquid material being only slightly compressible. Down to the saturation pressure, pressure decline causes a small increase of volume and a corresponding minor decrease of density. When the saturation pressure is passed, further reduction of pressure causes a rapid change. Gas escapes from solution, and two phases are thereafter present. The liquid shrinks and at the same time becomes more dense. With continued reduction of pressure the gas phase grows in volume, both by augmentation through further escape of volatile material from the liquid, and by expansion; the liquid phase continues to shrink because the volumetric loss of material to the gas far exceeds the slight tendency of the remaining liquid to expand with decline of pressure. Within the range of moderate to high pressure the shrinkage of the liquid phase is very nearly directly proportional to the pressure decline and to the weight of gas released from solution.

As a combined result of the changes taking place, the total volume of the oil-gas mixture continuously increases with decline of pressure. This fact has led many to think of reservoir liquids as expansible materials that increase in volume with reduction of pressure. It is very important to note that the liquid does not expand;

the liquid phase actually shrinks; the apparent expansion comes entirely from the fact that the volume of the liberated gas phase always exceeds the shrinkage of the liquid phase.

Viscosity—Viscosity is that property of a liquid that describes its resistance to flow. It is the opposite of fluidity. Water has relatively low viscosity, but molasses has a high viscosity. At the saturation pressure the viscosity of a reservoir liquid is at a minimum. At a pressure higher than saturation the effect of compression is to increase slightly the viscosity of the liquid oil. When the pressure is reduced below the saturation pressure and dissolved gas escapes from solution, the viscosity of the remaining liquid oil phase increases because of the loss of the lighter components.

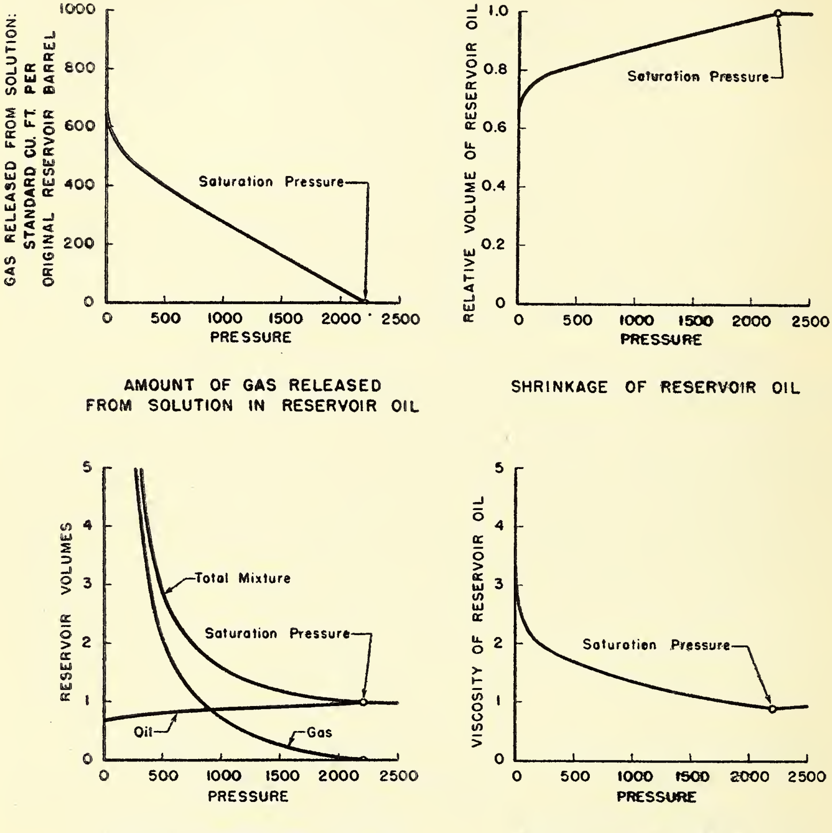
The viscosity of a typical reservoir oil increases several fold when the pressure is reduced from the saturation pressure to atmospheric. Since the ease with which oil can move through a reservoir rock is directly related to its fluidity, it is readily apparent that the increase of viscosity that results from decline of reservoir pressure and release of gas from solution will adversely affect oil recovery.

Interfacial Tensions—Surface tension is that property of a liquid that causes an isolated drop or bubble to assume a spherical shape. The surface of the liquid is under tension because the molecules comprising the liquid exert an attraction for each other. This attractive force arising within the liquid causes the liquid to assume the shape that will have a minimum exposed surface. When the surface of a liquid is in contact with a gas the interfacial tension at the gas-liquid boundary is commonly called the surface tension. When two liquids are in contact, or when a liquid contacts a solid, molecular attractive forces are effective on both sides of the common contact boundary, so that an interfacial tension is always present at the boundary between a liquid and a gas, between two immiscible liquids, or between a liquid and a solid. Surface forces have important effects on the configurations of the phases within the small pores of reservoir rocks, on the distribution of the phases within the reservoir, and on the oil recovery.

The surface tension of an oil against the gas released from solution continuously increases as the pressure is reduced. Very few determinations have been made of the interfacial tension of reservoir oils against connate water or subsurface brines. The limited available data indicate, however, that the reservoir oil-water interfacial tension decreases when gas is released from solution by pressure reduction.

Graphical Representation of Behavior

The effects of reservoir pressure decline on the amount of dissolved gas released from solution in the reservoir oil, on the shrinkage of the reservoir oil as the gas is released, on the resultant reservoir volumes of the oil and its liberated gas, and on the viscosity of the reservoir oil are illustrated in Figure 8 for a typical reservoir oil.



AMOUNT OF GAS RELEASED FROM SOLUTION IN RESERVOIR OIL

SHRINKAGE OF RESERVOIR OIL

RELATIVE RESERVOIR VOLUMES OF OIL AND RELEASED GAS

VISCOSITY OF RESERVOIR OIL

Fig. 8—Effects of Reservoir Pressure Decline on Properties of Reservoir Oil and Gas

Figure 9 shows data from a number of different pools on the relationship between the amount of gas dissolved in a barrel of oil, as measured by liberation at the surface, and the formation volume factor of the reservoir oil.

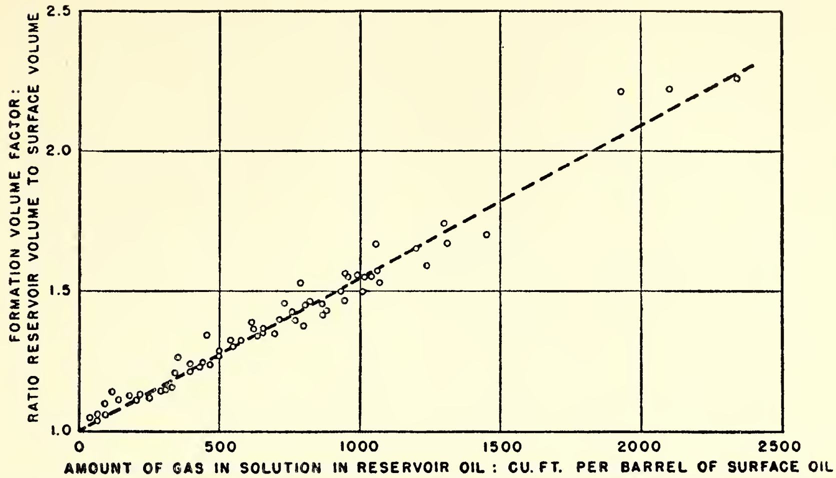


FIG. 9—**Effect of Dissolved Gas on Formation Volume of Reservoir Oil**

RESERVOIR GAS

The primary difference between a reservoir gas and a reservoir oil is the difference in composition. Whereas reservoir oil is usually a mixture in which the heavier, normally liquid hydrocarbons comprise the bulk of the material, with the dissolved volatile hydrocarbons assuming subordinate importance, reservoir gas is usually a mixture in which the dominant constituent is methane and the heavier hydrocarbon constituents are subordinate.

PHASE BEHAVIOR

As in the case of the typical liquid crude oil, the reservoir state of a gas is sometimes obvious, particularly if the reservoir is shallow and the pressure is low. Large quantities of gas, however, are produced from deep reservoirs, and the gas is often accompanied by so much material separated at the surface as liquid that the reservoir state is by no means obvious. In such cases the reservoir state must be determined experimentally.

Mutual Solubility of Oil and Gas

The reason for the difficulty in identifying properly the state of the petroleum in a reservoir is that the normally liquid and normally gaseous constituents of the petroleum are mutually soluble. At low pressure the phenomenon of solution is commonly considered primarily in relation to liquids. Thus, air will dissolve in water to form a solution, but the solution of water in air to form a humid atmosphere is commonly thought of as simply evaporation or vaporization. All liquids have vapor pressure; if the vapor pressure of a liquid is high, the liquid is said to be volatile; if it is low, the liquid is said to be non-volatile. Any liquid will evaporate into any gas until the concentration of that material in the gas is sufficiently high to resist further vaporization. Vaporization ceases and a stable condition is reached when the escaping tendency of the material is exactly the same in the gas and liquid phases.

If a liquid phase and a gas phase, each containing a mixture of materials, are confined together at the same temperature and pressure, each constituent will distribute itself between the two phases in such proportions as to bring about a stable condition of equilibrium. If the pressure is changed, a new distribution will take place. At low pressure the changes in composition of the gas and liquid are readily predictable if the vapor pressures of the constituents are known. For example, if normal pentane is distributed between crude oil and gas in a closed container at low pressure, the amount of pentane in each phase will be such as to give it equal escaping tendency from each. The escaping tendency of the pentane in the liquid will be approximately equal to the product of its molecular concentration in the liquid times its vapor pressure. The escaping tendency of the pentane in the vapor will be approximately equal to its concentration in the vapor times the total gas pressure. If the pressure were doubled, the escaping tendency of the pentane in the gas phase would be increased approximately twofold, which would unbalance the equilibrium and force pentane to pass from the gas to the liquid to equalize the escaping tendencies again.

This behavior at low pressure may be summarized by the statement that at low pressure the solubility of a gas in a liquid increases with increase of pressure, and a volatile material distributed between a liquid and a gas is condensed into the liquid by increase of pressure. Thus, increase of gas pressure *normally* suppresses vaporization.

Retrograde Condensation

The behavior described as normal is characteristic of petroleum at the temperatures encountered in most production operations until the pressure exceeds 500 pounds per square inch. Serious deviation from the normal sets in between 500 and 1,000 pounds per square inch; at higher pressure the behavior is not at all the same.

The concentration of methane dissolved in the liquid phase continues to increase with increasing pressure, causing the liquid oil phase to become lighter, more compressible, and thus more like gas. Conversely, the higher the pressure, the more dense the gas phase becomes, the less compressible, and the more like a liquid. As the two phases become more alike the less volatile constituents of the mixture begin to dissolve into the gas phase, adding further to its density and making it still more like a liquid. At the critical temperature and pressure of a mixture this process reaches a state at which the gas and liquid phases have identical composition and identical properties in all respects, so that the two phases become indistinguishable and coalesce into a single, homogeneous phase.

When considered in terms of the normal behavior of mixtures, the increasing concentration of hydrocarbons heavier than methane in the gas phase appears to be caused by their acquiring at high pressure an abnormal volatility that makes them evaporate into the gas instead of condensing from the gas as the pressure is increased. Whatever may be the reason for the abnormal behavior, the significant fact is that at high pressure the intermediate and heavier hydrocarbons pass from the liquid into the gas phase with increasing pressure and are condensed back into the liquid by pressure reduction, which is the opposite of their behavior at low pressure. The abnormal behavior associated with high pressure has been called *retrograde condensation* or retrograde vaporization. Although abnormal volatility is first noticeable to a pronounced degree in the pressure range between 500 and 1,000 pounds per square inch, retrograde effects are not usually important in petroleum reservoirs until the pressure exceeds 2,000 pounds per square inch.

Phase Diagrams

The behavior of gas in a reservoir can best be visualized in relation to its phase diagram. In contrast to the usual reservoir oil, the critical temperature of a gas is an important factor, and the dew-point line of the phase diagram and the two-phase region within the dew-point loop must be investigated. Figures 10-A, 10-B, and 10-C show phase diagrams of typical reservoir gases, illustrating the variety of conditions that may be encountered. In each diagram the reservoir temperature and pressure are indicated by the point R, the surface temperature and pressure by the point S, and the critical temperature and pressure of the reservoir gas by the point C. The dotted lines and arrows indicate the temperature and pressure changes undergone by the reservoir gas during the process of production. The gas that enters a well bore is cooled during its travel to the surface and through the surface separation equipment. Its temperature and pressure change in the direction indicated by the line from R to S. The gas remaining in the reservoir is at constant reservoir temperature, but as gas is withdrawn the reservoir pressure declines, so the pressure of the reservoir gas follows the line from R to T_R.

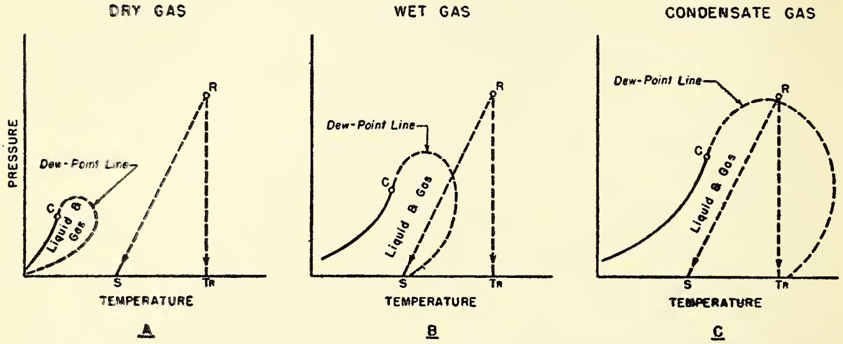


Fig. 10—Phase Diagrams of Typical Reservoir Gases

Dry Gas—Figure 10-A is a phase diagram of a typical dry gas. Such a gas is usually mostly methane with only minor amounts of ethane and heavier constituents. It contains no very heavy hydrocarbons. The entire two-phase region is within a temperature region below that to which the gas is ever subjected during production. Such a gas will not condense during the production process, and no hydrocarbon liquid will be trapped in any conventional surface separation equipment. Any heavier hydrocarbons that may be present in this type of gas can be recovered only by means of a natural gasoline plant.

Wet Gas—Figure 10-B is a phase diagram of a typical wet gas. The gas is still predominantly methane, but contains significant quantities of intermediate hydrocarbons boiling within the range of natural gasoline. No more than traces of very heavy hydrocarbons are present. The two-phase region of the gas is all below the reservoir temperature, and the gas that remains within the reservoir never condenses. The gas that is produced, however, is cooled to a temperature within the two-phase region. When it passes through the temperature and pressure of the dew-point line the less volatile hydrocarbons begin to condense to liquid. This liquid may be separated from the gas in a surface separator maintained at a temperature and pressure within the two-phase region of the phase diagram. The liquid separated from this type of gas was formerly called distillate. It is usually colorless and of a much lower density than most crude oil. Its gravity is usually above 60° API.

Because of the volatile character of the intermediate hydrocarbons contained in this type of gas, conventional surface separation equipment usually provides relatively poor recovery. It is common practice to strip the butanes and heavier materials from the gas in a natural gasoline plant when the amount of gas and its yield are such as to justify the cost of their recovery.

Condensate Gas—Figure 10-C is a phase diagram of a typical gas encountered in deep, high-pressure reservoirs. Methane is still the major single constituent, but intermediate and heavier hydrocarbons are present to a significant degree, including, frequently, even hydrocarbons separable as solid waxes. The two-phase region of this type of gas extends to temperatures above the reservoir temperature. The material is in the gaseous state solely because of the high reservoir pressure. This type of gas is most commonly encountered in reservoirs deeper than 5,000 feet and having reservoir pressures exceeding 2,000 pounds per square inch.

Condensation of hydrocarbon liquid from this type of gas will take place both in the reservoir and in surface equipment whenever the pressure is reduced to a value lying within the two-phase region.

The reservoir gas may be initially at its dew-point pressure, or it may be initially at a pressure above the dew point. In either event, condensation of liquid hydrocarbons takes place whenever the reservoir pressure is reduced to a value below the dew-point pressure. Since the heavier hydrocarbons initially contained within the gas but condensed within the reservoir by reduction of pressure are normally only slightly volatile and are found in the gaseous state because of the abnormal volatility temporarily imparted to them by the high pressure, they do not completely revaporize as the reservoir pressure is reduced to a low value, but remain in the reservoir in the liquid state. The techniques required to prevent the loss of those liquid hydrocarbons that might condense within the reservoir are discussed in later chapters.

The gas that leaves the reservoir is subjected to pressure reduction and to cooling, each of which causes condensation of the heavier and intermediate hydrocarbons. The liquid material may be separated from the gas in conventional surface separators in the same manner as crude oil and gas are separated. The recovered liquid is commonly called *condensate*. Typical condensates grade from colorless liquids of high API gravity to light-colored liquids of red, green, or blue cast with gravities as low as 40-45° API. Condensates produced from deep reservoirs are indistinguishable from nonasphaltic, light crude oil. They have the same color, the same density, and the same boiling-point range. Actually, they are crude oil, in that they are the same material except that in the particular reservoir in which found they are associated with sufficient methane at high enough pressure to evaporate them into the gas phase until such time as the pressure is reduced.

Surface yields of condensate from reservoir gas vary from one or two barrels to as much as 200 barrels or more from a million cubic feet of separated gas, depending upon the composition of the reservoir gas. There is no sharp demarcation between dry gas, wet gas, and gas that contains condensate. Reservoir gases grade continuously in composition from one extreme to the other and, without break, continuously into the range of reservoir liquids. The differences illustrated show the three types of behavior possible; they are important in relation to proper recovery techniques, but they do not indicate that there are different kinds of reservoir gas. The present tendency is to draw a distinction solely between dry and wet gas, and to classify all condensed liquids as condensate, whether the condensation takes place by cooling, by pressure reduction, or by a combination of both. Since it is not possible to tell from the character of the liquid alone, or from its yield, whether the gas will or will not condense within the reservoir during the production process, suitable experimental investigations must be employed to determine the phase behavior of the reservoir material.

PERTINENT PROPERTIES OF RESERVOIR GAS

The pertinent properties of the reservoir gas are its composition, its density, its volume expansion with pressure reduction, its state within the reservoir, its dew point, the condensate yield, the amount and composition of the liquid that may condense within the reservoir, and the ultimate yield of gaseous and liquid components recoverable at the surface.

Sampling of Reservoir Gas

Subsurface samples of reservoir gas taken at the bottom of a well contain too little material for the extensive tests required to analyze completely the behavior of a reservoir gas. Accordingly, it is necessary to sample the produced gas and liquid at the surface and to recombine these samples in the proper proportions to yield a mixture having the composition of the reservoir material.

Two methods of surface sampling are commonly employed. One is to sample gas and liquid from a conventional surface separator through which the well product is flowed at sufficient rate and for a long enough time to obtain a constant rate of yield of gas and liquid. The separator is usually calibrated, and the liquid production is usually measured directly in the separator.

In the other method, a small tube is inserted vertically through the wellhead into the tubing of a well, or is inserted into a flow line leading from the well, preceded by a suitable mixing device, and a small portion of the stream of mixed gas and liquid is passed through miniature separation equipment, where certain determinations are made directly on the flowing stream. It is the usual practice, when miniature separation equipment is employed, to pass the main stream of well product through a full-scale separator and to check the yield in the miniature separator when it is maintained at the same temperature and pressure as the full-scale equipment.

Composition

The composition of the reservoir gas is determined by analyzing separately by fractional distillation the samples of gas and of liquid taken from the field separator. If the well produces dry gas with no condensed liquid, the composition of the produced gas is the same as that of the reservoir gas. When both gas and liquid are produced, the composition of the reservoir gas is determined by combining their separate analyses in the correct proportions.

Samples taken for determination of the composition of the reservoir gas are preferably taken at a separator pressure between 500 and 1,000 pounds per square inch to minimize the concentration of heavier hydrocarbons in the gas sample. One technique used to increase the accuracy of the determinations is to pass a metered portion of the gas from the separator through activated charcoal under conditions that will retain in the charcoal the butanes and all heavier hydrocarbons. The composition of the separator gas is then determined by combining with a conventional gas analysis the results of an analysis of the material retained in the charcoal.

The separator liquid is analyzed in the same manner as is a subsurface sample of reservoir oil. However, since the heavier materials may undergo a change of state within the reservoir, it is necessary to carry the fractional distillation beyond those hydrocarbons normally identified in oil samples. True-boiling-point fractional distillations or other distillation procedures are employed to determine the complete boiling range of the heavier materials in condensates.

Density and Expansion

Determination of the amount of hydrocarbon material present in a reservoir requires that the amount contained within a unit volume of reservoir pore space be known. For this purpose, the density of the reservoir gas is usually obtained by placing a recombined sample of separator gas and separator liquid in a pressure container, restoring the sample to a single-phase condition by compression at reservoir temperature, displacing from the container at reservoir temperature and pressure a measured volume of the reservoir gas, and weighing the displaced quantity.

A second method is to calculate the reservoir density from the composition.

The expansion of the reservoir material with reduction of pressure is determined directly by measuring in a pressure container at reservoir temperature the volume of a known amount of recombined reservoir gas at a series of pressures from reservoir pressure down to atmospheric pressure.

State of Reservoir Gas

Determination of the state of the reservoir material requires a determination of the phase-boundary pressure at the reservoir temperature, together with specific identification of the phase boundary as a bubble point or a dew point. If the phase boundary is a bubble point the single-phase reservoir material is liquid; if the phase boundary is a dew point the reservoir material is gas.

Several experimental techniques are employed for determination of the state, but in all of them the fundamental principles are the same. When the pressure of a confined sample of reservoir material within the two-phase region is progressively increased, the volume of liquid in equilibrium with the gas either increases or decreases until a pressure is reached at which the sample either becomes all liquid or the liquid disappears entirely. If the sample becomes all liquid, the pressure at which the last trace of free gas disappears is the bubble-point pressure, and the single phase remaining is reservoir liquid. If the liquid disappears entirely, the pressure at which the last trace of liquid disappears is the dew-point pressure, and the single-phase material remaining is gas.

The required experimental determinations may be carried out by observing directly or indirectly the changes that result from systematic variation of the pressure of a confined sample of the reservoir material. A pressure vessel with a transparent window is sometimes employed to permit direct observation of the phase changes. The phase changes may also be determined by field tests in which a portion of the well stream is passed continuously through a miniature separator maintained at reservoir temperature.

Either of these approaches may be used to determine also the volume of liquid that will condense within the reservoir at reduced reservoir pressure.

Condensate Yield

The ultimately important factor to be determined is the potential condensate yield from a reservoir gas. Since various techniques may be employed to produce a gas reservoir, some of which involve maintenance of the reservoir pressure and some of which do not, and since various techniques may also be employed to remove the condensate from the gas after it has left the well, it is necessary to a complete determination of the potential condensate recovery to know the composition of the reservoir gas that will enter the well at any reservoir pressure.

Several different procedures are used to obtain the composition of the produced gas as a function of the reservoir pressure. The most complete information is obtained through tests conducted at the well with miniature separation equipment of the type already described. The test separator is heated to reservoir temperature and is used to represent the reservoir, the pressure being systematically reduced to represent reservoir pressure reduction. The composition of the reservoir gas at reduced pressure is obtained directly by suitable analysis of the gas withdrawn from the heated test separator. The amount and composition of the liquid that will condense within the reservoir are determined by measurement of the rate of accumulation of liquid within the test separator and analysis of withdrawn liquid samples. Such tests are frequently supplemented by calculations based on the composition of the gas and liquid samples withdrawn from the test separator at a series of pressures. The composition of the reservoir gas may also be determined directly by analysis of the gas displaced from a heated pressure vessel in the laboratory. The field testing procedure has the advantage of yielding sufficiently large samples for complete assay of the condensate, whereas the laboratory samples are always of relatively small volume.

SURFACE RECOVERY OF CONDENSATE

The term condensate normally refers to the liquid that condenses from the gas and is physically separated in liquid form at the surface. Since the amount of material that will be collected in a stock tank by a simple separation procedure depends not only on the composition of the material leaving the well but also on the temperature and pressure of the separation and on the number of stages of separation, the condensate yield of a gas is not a fixed quantity. For the same reason the condensate *content* of a gas can be referred to only in a semi-quantitative sense when the designation is employed to refer to the amount of condensible liquid contained in the gas. For these reasons, it is preferable to evaluate a reservoir gas in terms of the specific composition of all hydrocarbons heavier than methane, either individually or by suitable groups.

From the composition of the reservoir gas it is possible to calculate the amount and composition of the liquid that will condense from the gas in surface separators at moderate temperature and pressure, and the amount of liquid that will be recovered in a stock tank. From such calculations the optimum temperatures and pressures for separation in either single-stage or multiple-stage arrangements may be determined. The liquid yield obtainable in a stock tank may also be determined directly by use of the miniature test equipment already described. To determine the condensate yield, the gas from the heated test separator is passed into a second separator maintained at the temperature and pressure of normal field separation, and the liquid from the second separator is passed directly into a receiving vessel and measured. Laboratory tests also provide a direct but approximate measurement of the liquid recoverable in a stock tank, but do not simulate the field separation conditions.

Physical separation alone is not capable at normal surface temperatures of removing completely from the gas all of the potentially recoverable intermediate hydrocarbons. When the volume of gas produced is such as to warrant the capital investment required, absorption-type or refrigeration-type processing plants are employed to effect more complete recovery.

Condensed Water

It is often overlooked that water is always present in petroleum reservoirs and that the reservoir gas is always substantially saturated with water vapor at the temperature and pressure at which it enters the well bore. The change of temperature and pressure of the gas from subsurface to surface conditions is nearly always such as to cause condensation of a part of this water, both within the well during the upward travel of the gas and in surface equipment. This water is sometimes mistaken as evidence of water influx in the liquid state from the reservoir into the well, and thus erroneously as evidence of proximity of the well to the edge or bottom water forming the reservoir seal. Water vapor condensed from the gas is nearly always non-saline, whereas edge or bottom water in most petroleum reservoirs is salty.

INITIAL RESERVOIR CONDITIONS

The physical environment within which petroleum is found influences the distribution of the phases within the reservoir, the properties of the oil or gas, and the potential recovery. Particularly important are the texture and character of the porous rock comprising the reservoir, the variation of rock properties throughout the reservoir, and the temperature and pressure.

Earth Pressures and Temperatures

The porous sedimentary rocks comprising most of the outer surface of the earth are filled with water except at very shallow depth. This water usually grades from fresh near the surface to saline at greater depths. The water exerts a hydrostatic pressure because of its density, and compresses the oil and gas in all petroleum reservoirs. Except in or adjacent to mountainous areas, the hydrostatic pressure in the earth is usually found to increase by 430 to 460 pounds per square inch for each 1,000 feet of depth below the regional average surface elevation. Although pressures lower than normal have been found in some areas, the expected initial pressure in a petroleum reservoir 5,000 feet deep would usually be around 2,250 pounds per square inch; a reservoir at 10,000 feet depth would normally have an initial pressure near 4,500 pounds per square inch.

In some areas, reservoirs deeper than 5,000 to 7,000 feet are sometimes found to have an initial pressure much higher than that normally expected. The cause of these abnormal pressures is not fully understood, but they are believed to reflect peculiar local conditions and to be indicative that the petroleum reservoir is in some manner sealed from fluid communication with its surroundings.

The temperature in the earth also increases with depth. Temperatures have been measured at various depths in both mine shafts and wells. In most petroleum reservoirs the temperature is from 6°F. to 20°F. higher for each 1,000 feet of depth than the mean annual surface temperature at the locality.

The pressures and temperatures of petroleum reservoirs are measured by lowering to the bottom of a well subsurface pressure gauges and subsurface thermometers. Many different types of instruments have been constructed for this purpose; some record the pressure and temperature continuously while they are being lowered down a well, and others record merely the maximum pressure or temperature encountered.

The temperature within a petroleum reservoir never changes significantly from its initial value. The reservoir pressure, on the other hand, changes when oil and gas are produced. Since both the pressure and temperature affect the state and properties of the petroleum in a reservoir, they must be measured if the reservoir is to be operated in an intelligent manner. The initial reservoir pressure should be measured as soon as possible after a reservoir has been discovered.

Distribution of Reservoir Fluids

Because of their differences in density, the water, oil, and gas in a petroleum reservoir, before they are disturbed by production, are usually segregated by gravitation to the extent permitted by the rock texture. Water is usually found at the bottom or lower edges of a reservoir, oil above the water, and gas above the oil. Deviations from this condition have been found in some reservoirs where geologically-recent structural movements have taken place or where gas or oil has recently invaded a reservoir from an extraneous source.

The connate water, however, is not confined to the lower portion of the reservoir, but is disseminated throughout the oil- and gas-bearing portion of the formation. It is presumed that oil and gas accumulated in porous rocks that were filled with water prior to accumulation of the petroleum. The initially contained water is never completely displaced; part of it remains as connate water. The retained water is contiguous with the oil or gas, occupying part of the same pore space. This water is held in place by surface forces, the effects of which are discussed in subsequent chapters. It is particularly significant, however, that the amount of connate water held in the pore space is directly dependent on the rock texture. The water wets most reservoir rocks and is held primarily in the smaller interstices in the rock. The relative amount of water in the pore space is greater in rocks of low permeability than in rocks of high permeability, and is very sensitive to the presence of hydratable clays or other mineral substances that offer large surface area for water adsorption. The percentage of connate water in the pore space in a petroleum reservoir is not constant, but varies with the height above the normal water level and with the texture and composition of the rock.

The boundary between edge or bottom water and reservoir oil, and the boundary between reservoir oil and gas, are not plane surfaces of discontinuity between one phase and the other but, instead, are transition zones within which the relative amounts of water, oil, or gas progressively change from predominantly one to predominantly the other. The gradations, like the distribution of connate water, are governed by surface forces and by the formation texture. The transition zones may range from a few inches to several feet in thickness.

Determination of Oil and Gas in Place

As pointed out in later chapters, proper operation of an oil or gas reservoir requires complete and thorough knowledge of the amount and distribution of the oil and gas originally contained within a reservoir at the time of its discovery, as well as of the properties of the original reservoir fluids. Furthermore, expenditures for development should be based on tangible information regarding the probable amounts of oil and gas potentially recoverable. Serious mistakes are sometimes made through failure to identify properly the state of the reservoir material and its bearing on the amount of petroleum contained within the formation.

Determination of the amount of petroleum in place in a reservoir requires, basically, a knowledge of the porosity of the petroleum-bearing rock, the amount of connate water present in the pore space, and the formation volume factor, or density and composition, of the reservoir fluids. The accuracy of the determination is obviously dependent on the thoroughness of the information procured during development on the vertical and lateral intervals occupied by oil and gas, the porosity, the connate water content, and the distribution of these latter two vertically and laterally throughout the reservoir. Equally important are the amount of oil or gas contained within a unit of available pore space and the recovery efficiency to be expected.

The formation volume factor has a very important effect on the amount of liquid potentially recoverable, particularly in deep reservoirs and in gas-condensate reservoirs. For example, a producing formation with 20% porosity and 30% connate water will contain 1,085 barrels of hydrocarbon material in one acre foot. In a shallow pool containing low gravity crude oil with a moderate amount of dissolved gas and a formation volume factor of 1.10, the hydrocarbon material in that pore space would represent 985 barrels of stock-tank oil in each acre foot. In a pool 8,000 feet deep with a reservoir pressure of 3,700 pounds per square inch and a temperature of 210°F., producing 50°API gravity oil with a dissolved gas-oil ratio of 1,500 cubic feet per barrel and a formation volume factor of 2.1, the same pore space would contain only 516 barrels of stock-tank oil in each acre foot. If, instead of crude oil, the same reservoir contained gas with a condensate yield of 50 barrels of 50°API gravity stock-tank liquid per million cubic feet of separated gas and a formation volume factor of 16.7, the condensate in place would be only 65 barrels of stock-tank material in each acre foot.

It is obvious that development expenses that might yield a satisfactory return from a pool containing some 500 barrels of crude oil in place in an acre foot of formation might lead to serious losses if the formation yielded only gas and condensate. The differences in possible yield from deep reservoirs producing on the one hand crude oil and on the other hand condensate are such that identification of the reservoir state of the material is critically important and should not be based on supposition.

TWO-PHASE RESERVOIRS

Petroleum reservoirs frequently contain both a liquid oil phase containing dissolved gas, and an overlying gas phase containing vaporized intermediate and heavier hydrocarbons. In such a case the reservoir is referred to as having a gas cap. A well completed near the top of the reservoir may produce only reservoir gas, and a well completed lower may produce only reservoir liquid. In reservoirs of this type, the characteristics of each phase must be known, but it is not usually necessary to determine the mutual effects of one phase on the other unless the producing conditions are such as to cause commingling of the phases within the reservoir or at the surface.

Difficulties arise in identifying the reservoir contents when the nature of the reservoir or the manner of well completion is such that the only wells available for test produce a mixture of reservoir liquid and reservoir gas instead of a single material. When such a condition is encountered it is frequently necessary to resort to a combination of the testing and analytical procedures required for reservoir liquids and reservoir gases. Subsurface sampling devices may sometimes be employed to obtain from the bottom of a well a sample representative of the reservoir liquid, even though the well may produce a mixture. In other cases it is necessary to combine the produced gas and liquid in the proper proportions in a pressure vessel at the reservoir pressure and temperature and to remove from the vessel separately the resultant equilibrium gas and liquid phases. Miniature separation equipment maintained at reservoir pressure and temperature may also be used to obtain separate samples representative of the reservoir gas and the reservoir liquid.

Once separate samples of the reservoir materials have been obtained, they may be examined individually by the procedures already outlined.

NEAR-CRITICAL PHASES

In the great majority of petroleum reservoirs it is possible to make a clear-cut distinction between reservoir liquid and reservoir gas. In some cases, however, the composition of the material is such that its critical temperature and pressure are very close to the reservoir temperature and pressure. When such a condition is encountered, a few degrees difference in temperature may make the material shift from one phase to the other without change of composition or material change of character. Conditions may even be encountered where, in a single field, the material in one formation may show the behavior conventionally associated with the liquid state, but identical material in a slightly deeper stratum at higher temperature and pressure may show the behavior conventionally associated with the gaseous state.

In cases of that sort, use of the terms liquid and gas becomes rather arbitrary; to the extent that the terms may imply behavior normally associated with the liquid state or the gaseous state they may be very misleading. Regardless of the state attributed to the reservoir material, the behavior with changes of temperature and pressure will be very much the same whether the material be called liquid or gas.

The significant fact from the standpoint of reservoir behavior is that a moderate reduction of reservoir pressure will cause the reservoir material to separate to a significant degree into two phases. If the reservoir material is called liquid, the resultant change will be attributed to high shrinkage caused by loss of a large quantity of dissolved gas. If the reservoir material is called gas, the same kind of change will be attributed to a large condensation of liquid.

The only sound procedure when material of this sort is encountered is to determine as completely as possible the phase behavior of the reservoir material and the properties of each phase at reduced pressures. The techniques previously described are applicable, particularly those used for the study of reservoir gas.

Reservoirs of this type behave in many respects like gas reservoirs having high condensate yield. Efficient recovery is not possible unless their character is taken into account in the recovery operation.

Chapter V

FUNDAMENTALS OF OIL RECOVERY

DIFFERENCE BETWEEN OIL PRODUCTION AND OIL RECOVERY

The technical task in oil recovery is tremendously complex and difficult, not only because of physical limitations, but because of the extremely misleading appearance of the problem. To all intents and purposes the production of oil appears to be an elementary process requiring no technical insight whatsoever. It is well known that fortunes have been made by lucky wildcatters who drilled wells in the right locations and produced millions of barrels of oil. In a sense, the production of oil is obviously simple. It requires merely the proper drilling of a well, an operation now requiring technical planning and control, but basically a straightforward mechanical process readily understood by the layman; the completion of that well in an oil or gas reservoir; and the opening of the well to a tank to receive the oil. The mere opening of a valve usually permits the oil to flow from the well, but if the flow is sluggish or ceases, mechanical pumping is installed to lift the oil from the bottom of the well.

The very obvious simplicity of the process of oil or gas *production* leaves one totally unprepared for the technically involved process of oil *recovery*. So effectively, indeed, was the latter problem hidden by the apparent simplicity of the former that oil was produced in this country for over half a century before there was any common awareness that there existed a recovery problem. Not until individuals with scientific training or an appreciation of technical considerations became interested in or employed in producing oil was it discovered that oil production, although a highly successful activity, did not recover all of the available oil that had been discovered and that something more was involved in obtaining from a reservoir the oil that did not flow readily into the well bore.

As has been pointed out in Chapter I, the adoption currently of measures designed to assure efficient ultimate recovery is a practical necessity as oil becomes more difficult and more expensive to find, and the required profit incentive exists, once it is known. The immediate problem is evidently one of making the facts better known. Each oil producer, each royalty owner, each individual or enterprise that has a direct effect on oil production must become aware of the fact that oil recovery is a technical process and must be treated as such.

Such knowledge, together with the technical developments required to implement it, is growing and spreading rapidly. When it is realized that the whole science of oil recovery has developed in a matter of some twenty-five years or so from a beginning based on the farsightedness of a few scattered individuals, and has developed in an environment in which its need was at first totally unforeseen and unrecognized, the accomplishments become impressive. The record to date, the present impetus, and the future incentive all provide assurance of a continued rapid growth of oil conservation in terms of increased efficiency of recovery. Such assurance, however, must not be permitted in any way to lead to a lessening in effort, but should serve rather to stimulate increased activity, in that the sooner the facts are known to everyone concerned, the sooner efficient practices will be universally adopted, and the greater will be the ultimate return.

There has developed during the last twenty years an activity known as reservoir engineering. It is based on the scientific study of oil recovery processes, and consists in the application of the knowledge so derived to control of the production of petroleum reservoirs in such manner as to obtain increased ultimate recovery. So rapidly is this activity expanding that the technology of oil and gas recovery is undergoing continual improvement as new scientific information comes to light and as new techniques are developed for its application. Because of this situation, a description of the technology of oil recovery cannot be considered a final analysis. It must be viewed as a transient interpretation of a development that may be radically improved during the next decade. This chapter presents certain fundamental concepts and the rudiments of their application in a manner believed to represent a sound interpretation of the technical information now available.

FUNDAMENTAL ELEMENTS OF THE TECHNICAL PROBLEM

The complex technical problem of oil recovery may perhaps be more readily understood by consideration, first, of those fundamental facts and principles that have been developed through research and observation of field records, and, second, of the application of those fundamentals to oil and gas reservoirs.

RESERVOIR PRESSURE

It has been mentioned in Chapter IV that at the time of their discovery petroleum reservoirs are under pressure. Basically, this pressure is hydrostatic, in that oil and gas reservoirs are isolated accumulations, and the great bulk of the pore space in all underground rocks is filled with water. The pressure in most petroleum reservoirs before any appreciable amount of oil or gas has been withdrawn is approximately equal to that which would be imposed by a column of water rising from the oil reservoir to the surface of the ground. Important exceptions to this generality are known; some reservoirs have much higher pressure and some reservoirs lower pressure than would be expected from the depth, but the important consideration is that every commercial petroleum reservoir is under pressure at the time of its discovery.

It is this pressure that makes the production of oil a simple process. When a well is drilled into a petroleum reservoir and a portion of that reservoir is opened to the well bore, oil or gas will flow into the well whenever the pressure therein is less than that in the surrounding reservoir. Thus, flow of oil or gas may be induced by the simple process of lowering the pressure at the bottom of the well by swabbing or pumping. Unless that flow is stopped by artificial means, such as by a closed valve, or by the development of an excessive head of fluid in the well bore, or by an obstruction of the sand face, flow will continue from the reservoir into the well so long as it is possible to maintain a well-bore pressure at the bottom lower than that of the reservoir. Hence, the straightforward process of oil production consists in progressively reducing the pressure in the well to maintain it at a level lower than that of the surrounding reservoir until the reservoir pressure is depleted, or the oil is exhausted, or the operation has become uneconomic.

This process is deceivingly elementary. The reservoir itself is an interconnected network of voids in porous rock. These rocks are usually so incompressible that substantial reduction of their pore volume is not possible. It is not until inquiry is made into the mechanism that sustains the reservoir pressure and permits or causes continued flow of oil into the well bore that it becomes apparent that there is a technical problem. It is rather natural to consider the reservoir oil to be a compressible liquid and to consider its continued flow into a well to be similar to the continued flow of compressed gas from a cylinder. Such, however, is by no means the case. Oil, like most liquids, is a material having very little compressibility. If it were necessary to rely solely upon the compressibility of the oil in a reservoir the results would be severely disappointing, for a relatively minute production would reduce the pressure throughout the reservoir, and no more oil would be forthcoming. As was shown in Chapter IV, it is not the compressibility of the oil upon which continued flow depends, but, instead, the compressibility of a two-phase oil-gas mixture, the volume increase of which upon pressure decline is due exclusively to the release of gas from solution and the expansion of that gas. The oil phase actually undergoes a shrinkage in volume as a result of the pressure decline; it is the action of expanding gas or of water entering the reservoir that sustains the pressure.

Oil Recovery a Displacement Process

It becomes obvious from these considerations that the recovery of oil is in reality a displacement process. A pressure differential causes oil to flow toward and into a well, but continued movement can take place only if there is present another material to fill the void space vacated by the oil and to maintain in that space the pressure required as the driving force for continued oil movement. Looked at in a different light, the oil does not flow from the reservoir but is expelled from it by a displacement process. The technology of oil recovery relies basically on a study of this displacement process and the factors that govern its efficiency.

As a practical matter, the only displacing agents effectively employed today in the recovery of oil are gas and water. Although various terms have been used to describe the mechanism, depending upon the fluid causing the oil displacement and whether that fluid originates within the reservoir or its environs, or is injected through wells, the important consideration is that the oil cannot expel itself from the rock but must be expelled by a second agent.

The Displacement Mechanisms

Dissolved Gas

The oil in a newly tapped reservoir is frequently saturated with dissolved gas at the original pressure. When a well is drilled and the pressure is reduced therein, flow from the reservoir to the well locally reduces the pressure in the formation, permitting gas to escape from solution and to fill a part of the void space formerly occupied by the oil. Initially, this escape of gas from solution and the resultant ejection of oil occur immediately adjacent to the well bore only; as the process proceeds, pressure is reduced at distances progressively further away from the well, and eventually oil is displaced from pores throughout the reservoir. This process of oil displacement through the agency of gas liberated from solution is commonly referred to as *dissolved-gas drive.* A certain amount of production by this mechanism occurs in all reservoirs in which the oil is initially saturated with dissolved gas at the original reservoir pressure; in many reservoirs it is the dominant mechanism throughout the producing life.

Expanding Gas Cap

If the saturated oil in the reservoir is overlain by free gas that occupies a part of the same continuous reservoir, the process of pressure reduction originating at the well is eventually transmitted through the oil zone to the gas cap. It reduces the retaining pressure and allows the compressed gas in the gas cap to expand, to invade the oil zone, and to drive oil toward the regions of reduced pressure. Such invading gas may eventually encroach throughout an entire oil reservoir. Operation of a reservoir under this mechanism of an expanding gas cap is commonly referred to as *gas-cap drive.*

Water Influx

In the event the oil reservoir comprises only a portion of a continuous porous and permeable rock formation in which water fills the pores outside of the zone occupied by oil and gas, and if no barriers are present, the pressure reduction that proceeds from the well bore progressively through the oil reservoir is transmitted eventually to the water. Since water, like oil, is a fluid and is under pressure, the water also flows in the direction of reduced pressure toward the reservoir and the well. Water from the surrounding formation thus encroaches into the oil reservoir, and in so encroaching it displaces oil from the porous rock adjacent to the aquifer and drives it toward the well bore. Provided an ample supply of water is available, and provided the continuity and permeability of the reservoir rock are such as to permit its influx in substantial quantities, the entire oil reservoir may eventually be invaded by water, until water reaches and drowns out all wells. Such a process may occur regardless of whether the oil was originally saturated or undersaturated with gas. Under this operation, water may become the dominant fluid agent effecting the displacement of the oil, and water occupies the void space formerly filled by oil. Operation of an oil reservoir in this fashion is commonly referred to as *natural water drive.*

Each of these natural displacement methods is commonly operative, either singly or in combination, in petroleum reservoirs. Their characteristics are different, the mechanism of oil recovery is different in many respects, and the efficiency of the recovery of oil under these three basic processes is different. Efficient recovery requires a complete understanding of each mechanism, and the utilization of the one that is most effective for a particular oil reservoir.

Supplemental Effect of Gravity

Although the process of oil recovery is basically a displacement, requiring the presence of either gas or water to occupy the pore space vacated by oil, the force of gravity, as well as the pressure gradient, must be considered whenever the direction of fluid motion may have a vertical component. During the later stages of depletion of an oil reservoir produced by the agency of dissolved gas alone, the dissolved gas originally available in the reservoir may have been so completely exhausted, and the remaining reservoir pressure may be so low, that gravity becomes the dominant force causing continued oil movement toward the well bore. When such a stage is reached the oil is produced primarily by gravity drainage. Even this mechanism is in part a displacement process in that as gravity drains oil from upper portions of the reservoir into the lower portions, or into the wells, the pore space vacated by the oil is filled with expanding gas at low pressure. Gravity is responsible for the original segregation of fluids within a reservoir; under some conditions it can be a primary agent for oil recovery; it is often important in modifying the effectiveness of the dominant drive.

Surface Effects and Multi-Phase Flow

The basic principles of fluid mechanics are applicable to the flow of oil and gas in underground reservoirs just as they are applicable to flow through pipe lines. Certain complicating factors are present, however, that must be taken into account in oil recovery. The complications arise primarily from two sources: first, the small sizes and irregular shapes of the interconnected rock interstices comprising the reservoir, and, second, the simultaneous occupancy of the same pore space by at least two, and usually three, separate fluid phases, water, oil, and gas. The physical structure of the pore network, the mineralogic composition of the rock, and surface forces determine the configurations of the fluids within the rock and the ease with which they will flow.

Fluid Saturations

It is helpful under these circumstances to adopt certain conventions and to employ several concepts not normally required in dealing with the flow of fluids in bulk. One simple convention is the use of the *saturation* as a measure of the fluid content of a rock. Under this usage, the volumes of water, oil, or gas contained in unit volume of the pore space in a rock are referred to as their fractional or percentage saturations. For example, if 100 cubic inches of total pore space contains 20 cubic inches of water, 50 cubic inches of oil, and 30 cubic inches of gas, the water saturation, S_w, is 0.20 or 20 per cent; the oil saturation, S_o, is 0.50 or 50 per cent; and the gas saturation, S_g, is 0.30 or 30 per cent. The sum of the saturations of all of the fluids present is always unity, or 100 per cent of the pore space.

Capillary Pressures

Another useful concept is the *capillary pressure*. Whenever two separate fluids are confined together in a small space the interfacial tension at their mutual contact boundary causes the interface between them to be curved, and there is a difference of pressure across the interface. This pressure difference is called the capillary pressure.

An interfacial tension always exists at the contact boundary between two immiscible liquids, between a liquid and a gas, and between a fluid and a solid. Liquid-liquid and liquid-gas interfacial tensions can be measured directly by various techniques, but the interfacial tensions at fluid-solid boundaries can be obtained only by indirect procedures. Familiar examples of the effects of interfacial forces are the rise of water or oil in a wick, the spherical shape of a droplet of water in air or a bubble of air in water, and the spreading of oil on a metal surface. All wetting phenomena are related to interfacial tensions.

The magnitude of the capillary pressure across a particular interface is fixed by the curvature and the interfacial tension; the smaller the curvature the higher the capillary pressure. The absolute magnitude of the capillary pressures in most petroleum reservoirs is not usually large, even though the pore spaces are often quite small. Their effects, however, are extremely important. Together with gravity, they control the original distribution of the fluid saturations within the reservoir, particularly the distribution of connate water; through their effect on the shapes of the fluid interfaces within the pore space they control in large measure the relative freedom of movement of the fluids present; and they affect to an important degree both the distribution of the oil saturation in contiguous segments of the reservoir during the recovery process and the ultimate oil recovery.

Relative Permeabilities

A basic law of fluid mechanics is that a fluid that completely fills the pore space will flow through a permeable formation at a rate directly proportional to the permeability of the formation and to the pressure gradient, and inversely proportional to the viscosity of the fluid. This relationship is known as Darcy's law. It is through the statement of this law* that permeability is defined as a property of the rock.

It has been found experimentally that when oil, water, and gas simultaneously occupy the same pore space each interferes with the flow of the other.

Under this condition it is no longer simply the permeability of the formation as a unique characteristic of the rock that governs

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*Rigorous statement of this law requires that the acceleration of gravity and the direction of flow be taken into account, the rate of flow being given by the equation

$$q = \frac{-K}{\mu}\left(\frac{\delta P}{\delta x} + \rho g \sin \alpha\right)$$

where q = rate of flow

K = formation permeability

μ = fluid viscosity

$\frac{\delta P}{\delta x}$ = pressure gradient in the direction x

ρ = fluid density

g = acceleration due to gravity

α = angle of inclination of the direction x, positive in the up direction. The units must be consistent.

the rate of flow; instead, the rate of flow of each fluid is proportional to the effective permeability of the formation to that specific fluid at the particular conditions of saturation existing. The concept of *relative permeability* has been introduced to deal with this situation.

The relative permeability of a reservoir segment to oil, or to gas, or to water at a particular saturation is usually expressed as either a fraction or a percentage of the permeability of the rock when completely saturated with a single fluid. The relative permeability to each of several fluids simultaneously present is not a fixed quantity for each fluid in a given rock specimen, but for each fluid varies with its saturation.

The relative permeability to oil has its maximum value, 100%, when the pore space is completely saturated with oil. It decreases as the oil saturation is reduced. Correspondingly, the relative permeability to gas or to water is zero when the pore space is entirely filled with oil, but rises rapidly as the oil saturation is reduced and the gas or water saturation is increased. It is particularly significant that for each fluid a certain minimum saturation is required before that fluid will flow at all. Conversely, experience has shown that there is no combination of oil, gas, and water saturations at which the relative permeabilities to all three phases are simultaneously zero; flow is always possible for at least one of the fluids.

Wetting

Another important phenomenon is *wetting*. Wetting of a solid by a liquid is commonly observed in the spreading of a liquid on a solid surface and the blotting of a liquid by a dry adsorbent material. Connate water is present in most reservoir rocks, and when present is probably always a wetting phase.

Wetting has an effect on the relative permeability of a rock to each of the fluid phases present. This effect arises from the effect of wetting on the direction of curvature of the interface between the fluids. This curvature causes the wetting liquid to occupy selectively the smaller interstices of the rock, the finer pores, and the corners adjacent to the grain contacts, and the non-wetting phase to occupy the larger openings. The larger openings offer less resistance to flow and are more permeable than the smaller openings. A small amount of gas in the presence of oil seriously reduces the relative permeability of a rock to oil because the gas occupies the most permeable channels and increases the resistance to the flow of oil. Conversely, in a rock whose physical structure and pore sizes are not affected by water a small amount of water does not seriously interfere with the flow of gas or oil, because the water occupies those interstices through which very little gas or oil could flow even if the water were absent.

Unfortunately, many reservoir rocks contain argillaceous material that is swollen due to adsorption of water and obstructs the flow passages, seriously reducing the permeability to any fluid. The permeability to oil or gas of such a reservoir rock with its connate water present may be an order of magnitude lower than would be measured if the connate water were removed and the rock were dried prior to measurement of the permeabilities. Further complications are introduced when water, oil, and gas are all simultaneously present, as is the usual situation in a petroleum reservoir. The relative permeability to a particular fluid at a given saturation is not a general characteristic of any rock material but is specific to the particular sample of rock being investigated. For these various reasons it does not suffice to have general information regarding relative permeabilities; it is essential, if a quantitative study of the recovery mechanism for a particular reservoir is to be made, to have actual determinations of the permeabilities to oil, gas, and water of samples of the reservoir formation under study. For this purpose it is necessary that cores be available that will represent adequately both the vertical and lateral variations throughout the oil-producing formation, and it is important that all permeability measurements be made with connate water present in the rock.

THE PROCESSES BY WHICH OIL IS RECOVERED

Although the same fundamental principles of fluid mechanics govern the action of oil, gas, and water in all petroleum reservoirs, the actual processes by which the oil recovery is obtained differ sufficiently in many important respects that their relative advantages and disadvantages may be most readily understood through a separate analysis of each. The commonly used natural displacement processes are dissolved-gas drive, gas-cap drive, and water drive. The designation natural is used to indicate that they occur through use of the gas or water originally contained within a reservoir or accessible to it from its surroundings. Recovery processes relying on injection of gas or water to carry out the oil displacement are often referred to as artificial. It makes little difference whether the gas used for gas-cap drive or the water used for water drive originate within the producing formation or be provided by injection. However, artificial gas drive and water flooding are frequently employed under conditions that differ materially from gas-cap drive and natural water drive.

Dissolved-Gas Drive

The basic requirements for production of oil under a dissolved-gas drive are, first, that the pressure in the well bore be reduced below that in the surrounding reservoir so that oil may flow toward the well, and, second, that dissolved gas escape from solution in the reservoir and occupy pore space voided by the produced oil. As soon as this process has begun the pore space immediately surrounding the well contains no longer just oil, but both oil and gas. The gas liberated from solution within the pore space as the result of pressure reduction will not at first flow into the well as free gas but will accumulate as small, isolated bubbles until a certain saturation is reached; thereafter, as the oil saturation continues to decline with production the liberated free gas will also begin to flow into the well. As the process continues and the oil saturation of the pore space is further reduced, a given pressure gradient will result in a continuously declining rate of production of oil and a continuously increasing rate of production of the liberated or free gas. The effect of this sequence of conditions is that as production continues the gas-oil ratio tends progressively to increase.

In this process the only supply of a displacement agent available for oil production is that initially stored in the form of gas dissolved in the compressed reservoir oil. As oil and gas are produced more reservoir space must be filled by the expanding gas released from solution. As a result, the reservoir pressure must continuously decline to make that gas available, and progressively less total gas remains in the reservoir to fill the increasing amount of reservoir space available to the gas.

Mechanism of the Oil Displacement

The mechanism of the oil displacement is most readily followed through analysis of the depletion history of an isolated segment of the oil-bearing formation. If the flow of oil is substantially horizontal, or if the conditions are such that the force of gravity is relatively small in comparison to the pressure gradients caused by production, the driving force acting to expel the oil is the pressure gradient. The same driving force is also acting to expel any gas that may be in the same pore space.

Before production starts, the reservoir segment contains only oil and connate water. The connate water is usually immobile and plays no part in the process except to reduce the amount of space available to oil and gas. As soon as production begins, pressure is reduced at the well, and shortly a pressure difference is established between the pressure in the reservoir segment under consideration and the reduced pressure at the point of oil and gas withdrawal. This pressure difference causes oil to flow out of the reservoir segment at a rate proportional to the pressure gradient and to the effective permeability of the formation to oil.

Removal of oil reduces the pressure within the reservoir segment, causing two things to happen: first, gas escapes from solution from all of the oil still remaining within the segment, and, second, the remaining oil shrinks because of its loss of dissolved gas. The released gas completely fills the pore space vacated by the produced oil as well as that vacated by shrinkage of the remaining oil. If it were not for this filling with gas of the vacated pore space the pressure within the segment would quickly vanish, and production would cease. The released gas maintains the pressure within the segment, the degree of maintenance being dependent on the amount of gas released from the oil for each increment of pressure decline and on the amount of space that it must fill. Since there must continue to be a higher pressure within the segment than toward the well, it is the released gas that makes it possible for the oil to continue to flow.

For a while the process continues as described. Only oil flows from the segment, and all of the released gas remains, building up the saturation of gas within the pore space. After the gas saturation has reached a certain amount, the magnitude being dependent on the texture of the formation, the process undergoes an important change. The formation acquires permeability to gas as well as permeability to oil, and a part of the released gas begins to flow from the segment along with the oil. Since the same driving force, the pressure gradient, causes flow of both gas and oil, the rate at which gas flows relative to the rate at which oil flows is directly proportional to the ratio of the permeability to gas to the permeability to oil. Thereafter, the efficiency of the process deteriorates rapidly. With each increment of oil production the oil saturation declines and the gas saturation increases; the permeability to gas rises and the permeability to oil declines, so that gas flows from the segment more and more rapidly relative to the rate of flow of oil. The condition is further aggravated by the fact that gas has very low viscosity; under equivalent conditions it will flow from fifty to several hundred times faster than typical reservoir oils.

The flow of gas has an immediate adverse effect on the pressure remaining within the reservoir segment. Instead of having merely to fill the space vacated by the produced oil and by shrinkage of the remaining oil, dissolved gas must be released in sufficient quantity, as well, to make up for the gas that is produced. The result is that the pressure must decline still more to release additional dissolved gas from the remaining oil. The release of additional dissolved gas causes still further shrinkage of the remaining oil, further reducing the oil saturation and increasing the gas saturation, which aggravates the situation still further by accelerating the flow of gas.

The result of these conditions is that the entire store of dissolved gas originally contained within the horizontal reservoir segment under consideration is soon exhausted, and with it the pressure. There then remains no driving force to cause continued flow of oil, and the production of oil ceases.

The process described for a segment of the formation takes place throughout the entire reservoir; the pressure declines and gas is liberated from solution everywhere. The result is that no matter where a well is located or how it is completed, gas can flow into the well bore; it is not possible by selective well completion or selective production to control the gas-oil ratio and thus to retain the liberated gas within the pore space to increase the recovery of oil.

Recovery Efficiency

The amount of oil recoverable by the process of dissolved-gas drive is fixed by the characteristics of the producing formation and of its contained fluids. These are factors over which the producer has no control. Since the factors are all fixed, it would appear that, provided adequate factual information were available from cores of the producing formation and from samples of the reservoir oil, including determinations of the relative permeability of the formation to gas and to oil at various saturations, it would be possible by a straightforward arithmetic procedure to calculate the oil recovery, the gas-oil ratio, and the reservoir pressure at any stage of depletion of a reservoir.

Such calculations have been made for typical isolated reservoir elements; unfortunately, however, the complexities become so great when an attempt is made to take into account for an entire reservoir the effects of variations of formation texture and all of the transient effects simultaneously occurring within various parts of the reservoir that the calculations become very involved. Nevertheless, they provide a very useful insight into the mechanism of the process, and they sharply reveal not only that the dissolved-gas drive is a fundamentally inefficient oil recovery process, but the reason for the inefficiency. They clearly show that oil recovery ceases because the gas becomes exhausted, and with it the reservoir pressure, and not because the oil has all been produced or because the oil saturation has been reduced to the point of zero permeability of the formation to oil.

Very direct and positive indexes to the actual efficiency obtained at depletion are available. Since all of the original supply of gas is produced, records of the total gas production, coupled with a determination of the amount of gas originally dissolved in unit volume of the reservoir oil, provide a direct measure of the total original oil content of the reservoir, and thus of the quantity remaining behind. Coring of oil-bearing sands depleted by this process, and secondary-recovery operations, whereby additional oil is recovered from depleted reservoirs, also provide direct measures of the remaining oil content.

The information available from all of these approaches shows that the oil recovery by this process is of a very low order, often in the range of only 10 to 30 per cent of the original content. Dissolved-gas drive is not only a basically inefficient process; it is a mechanism that cannot be made to become efficient except through substantial modification.

Gas-Cap Drive

The gas-cap drive consists in a progressive invasion of the oil zone by gas, accompanied by a directional displacement of oil away from the location of free gas and toward the wells.

The basic requirements are

1. An upper portion of the reservoir filled with gas or containing a high gas saturation.

2. Continued growth or enlargement of the gas-filled portion of the reservoir.

The required free-gas zone may originate in several ways, as follows:

1. It may be initially present as a free gas cap.
2. Under certain conditions it may be created by gas originally dissolved in the oil but released from solution as a result of reservoir pressure decline, which has migrated to and become segregated in the upper portion of a reservoir under the action of gravity.
3. The gas cap may be created artificially by injection of gas into the upper portion of an oil reservoir.

Whatever the original source of the free gas, the essential condition is that the fractional reservoir volume filled with free gas must expand or grow at the expense of the oil-filled fraction; this growth must take place in a selective manner that results in the displacement of oil in a structurally down-dip direction.

It is obvious that there must be certain differences between naturally and artificially maintained gas-cap drives, but these differences are more of degree than of kind. A gas cap may be created artificially by injection, on the one hand, of only that gas produced with the oil, or, on the other hand, by injection of sufficient additional gas from an extraneous source to maintain the reservoir pressure at a level equal to the original pressure throughout the producing life of the pool. In the former case, the reservoir pressure continuously declines and the gas cap grows by expansion as well as by augmentation. In the latter case, growth of the gas cap takes place only by augmentation.

Mechanism of the Oil Displacement

The mechanism by which the oil is recovered under this process is more readily understood by consideration, first, of the nature of the displacement when the reservoir pressure is held constant by gas injection, and, second, the differences that arise when the reservoir pressure is permitted to decline.

It is apparent that if the reservoir pressure is maintained at its original value no displacing fluid has access to the oil-filled pores of the reservoir rock except at or behind the advancing free-gas front, and the structurally lower portion of the reservoir retains its original condition of oil saturation until reached by the invading gas. The oil *production* at any time comes from the wells located in the oil-filled region, but the oil produced therefrom is replaced by oil moving ahead of the advancing gas. The net result, therefore, is that the recovered oil has come from the region behind the gas front. Thus, the process consists in causing oil to move from the upper portion and into the lower portion of the reservoir. The advantage of this process is that it is possible by selective location, completion, and operation of the wells to obtain the oil production from a section of the reservoir containing no free gas, and thus to retain within the upper portion of the reservoir the free gas that is necessary for the oil displacement. It is in this maintenance of segregated oil and gas zones within the reservoir that the gas-cap drive has an advantage over the dissolved-gas drive.

Unfortunately, the action of the invading gas as it encroaches into the oil-filled pores is not like that of a piston. Instead of cleanly displacing all of the oil and leaving each pore filled with gas, the invading gas is itself highly mobile and tends to flow along with the oil as soon as its saturation within the pore space has reached an adequate level. The only manner in which this forward movement of gas along with the oil may be resisted is by having the pressure in the oil zone higher than that in the gas zone. Such a pressure condition will prevail if the oil movement is brought about by the force of gravity. The conditions required may be visualized by consideration of a vertical pipe filled with water, closed at its lower end with a valve, and open at its upper end to the atmosphere. If the pipe were 100 feet high the pressure at the closed end would be 43 pounds per square inch, and the pressure at the open top would be zero. The pressure difference is caused by the pull of gravity and the density of the water. If the bottom valve were barely opened water would flow downward; the flow would be caused by gravity rather than by a pressure gradient, because flow within the pipe would be from low pressure toward high pressure. If a bubble of air were released in the center of the pipe it would move upward rather than downward; since air has lower density than water the pull of gravity would be insufficient to move the bubble downward, and the increasing water pressure in the downward direction would force the bubble upward. This effect is the same as buoyancy. If the gas advancing into an oil zone is to be prevented from flowing along with the oil and ineffectively displacing it, buoyancy must be used to resist the gas advance until the oil displacement is substantially complete.

If the flow were essentially horizontal, or if it were otherwise so conducted that the effect of gravity were eliminated, the degree of desaturation of oil taking place in an oil-filled reservoir segment invaded by free gas would be dictated entirely by the viscosity of the oil, the relative permeabilities of the rock to oil and to gas, and any local capillary pressure effects caused by the difference in oil and gas saturations ahead of and behind the advancing gas front. If, on the other hand, the displacement were so conducted as to be dominated by gravity, the local balance between the force of gravity and the capillary pressure gradient would govern the desaturation.

At any stage of depletion, wells open to the formation below the advancing gas front may be so operated as to produce oil unaccompanied by free gas, but wells open to the formation above and behind the advancing gas front will produce both free gas and oil. Unless the up-structure wells are closed in, or unless the free gas they produce is returned to the reservoir, these wells may completely dissipate the free gas and destroy the gas-cap drive. After the gas front has reached the lower limits of the reservoir it becomes impossible to avoid the production of free gas.

A gas-cap drive must cease whenever the reservoir supply of gas is dissipated; however, oil production may continue under gravity drainage. If the source of the drive is a natural free-gas cap not augmented or maintained by gas injection, the reservoir supply of gas will usually be dissipated shortly after the free-gas front has reached the lower level of the reservoir, when free gas can no longer be excluded from the producing wells. At this stage the gas-oil ratio will rise sharply and the reservoir pressure will decline rapidly. In the event the gas cap is maintained by injection, the volume of produced gas will usually become excessive shortly after the gas front has reached the lower level of the reservoir, and thereafter excessive injection costs will be incurred. In either event, the process is substantially complete when the gas zone has invaded the entire original oil zone.

Effect of Reservoir Pressure Decline

Without gas injection, a gas-cap drive can take place only by virtue of gas expansion. Decline of reservoir pressure to cause such expansion is then essential. If the volume of free gas initially present in the reservoir is large compared to the original total volume of reservoir oil, and if free gas is not dissipated during the oil production, the degree of reservoir pressure decline required to cause the gas cap to expand sufficiently to encroach through the entire oil zone may be slight, and the reservoir behavior may closely approach that obtainable with gas injection. If, on the other hand, the original free-gas cap is relatively small in volume, the reservoir pressure decline required for the necessary expansion may approach that experienced under a dissolved-gas drive. In any event, reservoir pressure decline of any magnitude will permit dissolved gas to escape from solution and to develop a certain degree of free gas saturation throughout the oil zone concurrently with the expansion of the gas cap. When such decline releases sufficient gas from solution to raise the gas saturation of the oil zone to the point at which the liberated gas can flow, reservoir conditions are substantially modified. Such gas saturation increases the permeability of the oil zone to gas and reduces the permeability to oil. The effect is to slow the displacement of oil into the lower portions of the reservoir, and relatively to facilitate the advance of free gas, causing the free-gas front to reach the lower end of the oil reservoir at a higher over-all residual oil saturation than otherwise. Under extreme conditions all evidence of distinct zones high in gas saturation and high in oil saturation may disappear. Exclusion of free gas from producing wells may become impossible, and displacement by dissolved-gas drive instead of by gas-cap drive may become dominant.

The adverse effects of reservoir pressure decline and release of dissolved gas may be overcome to a large extent if it is possible to conduct the displacement in such manner that oil movements throughout the reservoir are dominated by gravity and the liberated gas is forced to flow upward to the gas cap by buoyancy. Under such conditions the recovery efficiency may closely approach that obtainable under complete pressure maintenance. Particularly important under these circumstances is the necessity of producing only those wells completed in the lowermost sections of the reservoir, in order to prevent interception and production of the upwardly moving gas released from solution.

Recovery Efficiency

The chief limitation of the gas-cap drive is the inherent disadvantage of gas as a displacing fluid. Its low viscosity and its tendency to occupy the most permeable portion of the pore space permit gas to flow readily through the formation without displacing much oil. If displacement alone is relied on for the oil recovery, gas-cap drive has only moderate advantage over dissolved-gas drive. The advantage comes from delay of gas dissipation, from flushing of the oil zone by a substantially greater quantity of gas than is the case with a dissolved-gas drive, and, to the extent that reservoir pressure is maintained during the displacement, to suppression of shrinkage of the oil. Offsetting the favorable factors is the tendency of the advancing free gas to flow through the most permeable strata and to leave uninvaded the less permeable parts of the formation.

Since the gas-cap drive usually ceases shortly after the entire reservoir has been invaded by free gas, unless it is artificially continued by gas injection, the efficiency of the oil recovery is dependent primarily on the thoroughness with which the formation has been depleted of its oil content by the time the advancing gas front has reached the lowermost wells. The completeness of the oil desaturation depends to a very great extent on the degree to which the oil recovery has been obtained by a process of gravity drainage instead of by displacement by gas.

The available data indicate that with favorable reservoir conditions a properly controlled gas-cap drive employing gravity as the oil-moving force is capable of yielding very high oil recovery. Under less favorable conditions, or with improper control, the ultimate recovery of oil may not greatly exceed that obtainable by dissolved-gas drive.

Water Drive

Water drive is in many respects similar to gas-cap drive except that displacement of the oil, instead of taking place at and behind an advancing gas-oil interface, occurs at and behind the advancing water-oil interface. The process is one in which water invades and displaces oil from the pore space progressively from the outer boundaries of the reservoir toward the wells. If the oil contains no gas originally in solution, or if the reservoir pressure decline that causes the water to enter the reservoir is so slight as to permit only negligible release of dissolved gas, the oil recovery results almost entirely from the displacing effect of the water.

The basic requirements for this process are, first, an adequate supply of water accessible to the oil reservoir, and, second, a pressure differential between the oil-filled zone and the water-filled zone to induce and maintain water invasion. The water drive may be either natural or artificial. For a natural water drive to take place there must be immediately adjacent to the oil zone a large volume of water in the same formation, without any barriers between the oil and water, and a sufficient degree of formation permeability to permit the water to flow in adequate volume. In the event of barriers between the oil-filled portion of the formation and the water-filled portion, natural water drive is not possible, and water drive can be employed only by injection of water into the original boundaries of the reservoir.

The water-filled formation containing the oil reservoir may sometimes reach the surface within a few miles of the reservoir. In such a case the supply of water for invasion of the oil zone may become available through influx of surface water at the outcrop or through a decline of the water level in the aquifer. Such a condition, however, is not commonly encountered. The more usual condition for a natural water drive is that the water invasion takes place by expansion of water in the aquifer as a result of the pressure decline transmitted thereto from the oil reservoir. Since the compressibility of water is very slight, a natural water drive normally requires a very large and extensive aquifer containing a volume of water many times the volume of oil in the reservoir.

Mechanism of the Oil Displacement

The mechanism by which the oil is recovered with a water drive resembles very closely the mechanism of displacement of oil by an expanding gas-cap drive under conditions of continuously maintained original reservoir pressure. No displacing fluid has access to the oil-filled pores of the reservoir rock except at and behind the advancing water-oil front, and the higher portions of the reservoir retain substantially their original condition of oil saturation until reached by the invading water. The oil production at any time comes from the wells located in the oil-filled region, but the oil recovery has come from the region behind the water front. Thus, the process consists in the moving of oil from the lower portion into the upper portion of the oil reservoir, from where it is withdrawn. As in the case of the gas-cap drive, there is maintained in the reservoir a segregation into two zones: an upper region highly saturated with oil and a lower region depleted of oil. Also, as in the case of gas-cap drive, the effect of gravity may be an important element in helping to maintain the required segregation between oil and water. The pressure in the oil zone, which permits continued flow of oil into the wells, is maintained by the invading water.

Like gas, water does not displace oil from a porous rock by a piston-like action. As soon as water invades a section of the oil zone and displaces some oil, the water saturation rises, the formation acquires permeability to water, and water tends to flow along with the oil. Water does, however, because of its much higher viscosity, have a distinct advantage over gas as a displacement agent. Under conditions where gravity is not a factor and displacement takes place solely by virtue of a pressure gradient, a given volume of water introduced into a segment of pore space will eject substantially more oil than will the same volume of gas. It will also accumulate to a much higher degree, having less tendency than gas to flow on through with the oil.

In most reservoirs having natural water drive the oil-bearing formation is inclined rather than horizontal, and the flow is in an upward direction parallel to the bedding. Under such a condition there is a component of the force of gravity acting on each fluid in a direction counter to the direction of flow. Because of the higher density of water this force is greater on the water than on the oil and tends selectively to retard the water advance relative to the oil advance. Stated differently, buoyancy acting on the lighter oil tends to move it forward at a faster rate than the water, facilitating its displacement.

The difference between the oil saturation immediately ahead of and behind the advancing water-oil interface depends, in part, on the degree to which buoyancy has been effective. If the displacement is dominated by buoyancy very little recoverable oil remains behind the interface; if buoyancy has been relatively unimportant, recoverable oil remains behind the interface and continues to flow forward along with the water. Under the latter condition, the amount of oil that remains at any point in a uniform element of the producing formation depends on the formation texture, the viscosities of the oil and the water, and the amount of water that has flowed past the point. In most water-drive reservoirs the oil displacement does not occur entirely at the water-oil interface, but to some extent continues from the water-invaded portion of the reservoir.

After the water-oil interface has passed a well its water production progressively increases, and its oil production continuously declines. The process is complete, and abandonment of the reservoir occurs, when the oil production of the uppermost wells reaches so low a value as to be inadequate to defray the operating costs. It is pertinent to note that in this process it is not dissipation of the reservoir pressure that causes the production of oil to cease, but depletion of the oil content to such a condition that the reservoir can no longer yield oil at a commercial rate. In most reservoirs depleted by water drive the reservoir pressure remains at a relatively high level at abandonment.

Although in many natural water-drive pools relatively large volumes of water are available for flushing the oil zone, the amount available at a satisfactory level of reservoir pressure is sometimes limited. It then becomes important to avoid dissipation of the water. The segregation of fluids within the reservoir into two zones, one highly saturated with oil and the other invaded by water, makes it possible selectively to produce oil free or relatively free from water from wells open to the formation in only the upper portions of the reservoir. With a properly managed operation it is possible to avoid excessive water production until almost the entire oil zone has been invaded. When excessive water production is not avoided it is often necessary to inject the produced water into the reservoir in order to maintain the water drive and the reservoir pressure.

Effect of Reservoir Pressure Decline

Since a pressure differential between the aquifer and the oil reservoir is a necessary condition for a natural water drive, a certain degree of reservoir pressure decline must take place to permit a water drive to become operative. Provided the permeability of the formation is reasonably high and the rate of oil production is not excessive, a moderate decline of reservoir pressure usually suffices to permit adequate water influx. Under such conditions it usually makes little difference whether the reservoir oil was saturated or not with gas at the original reservoir conditions, in that a moderate decline in reservoir pressure will not develop within the reservoir sufficient gas saturation for the resultant displacement of oil by gas to become an important part of the recovery process or for the free gas to reach such saturation as to flow as a separate phase into the wells.

If, for any reason, the reservoir pressure decline becomes excessive, a substantial portion of the oil production may result from the liberation of dissolved gas concurrently with the advance of water. Such liberated gas cannot be excluded from wells, and the wells selectively opened into the upper portion of the reservoir for the exclusion of water may produce excessive quantities of free gas along with the oil. It may become impossible under such circumstances to identify the effect of the invading water; in extreme cases reservoir pressure may decline so rapidly as to cause the oil to be produced predominantly by dissolved-gas drive, leading to abandonment of the reservoir as a result of a low order of oil production before the advancing water has had a chance to flush the entire reservoir. Effects of this sort are encountered in reservoirs in which the permeability of the formation is so low as to make it impossible for the water to keep pace with a reasonable rate of oil production, and in reservoirs having high permeability but produced at a rate such that water invasion cannot take place under the available pressure differentials in sufficient volume to replace the oil produced. In some instances, excessive decline in reservoir pressure results from the production of excessive quantities of water.

Recovery Efficiency

In most reservoirs produced by natural water drive the available supply of water is ample to flush the entire oil zone. Accordingly, the ultimate efficiency of the recovery of oil depends primarily upon the extent to which the advancing water has been made to encroach through all parts of the oil reservoir and the thoroughness with which it has flushed the flooded portions of the formation by the time the operation has become uneconomic.

Under favorable conditions a properly operated water drive is capable of yielding a high degree of recovery efficiency. Data on the ultimate recovery from a number of water-drive reservoirs indicate that the amount of oil remaining in the formation at abandonment may average as low as 20 to 25 per cent of the pore space when the reservoir oil has low viscosity. High oil viscosity, low permeability, and excessive reservoir pressure decline reduce the recovery.

ARTIFICIAL GAS DRIVE AND WATER FLOODING

Regardless of the nature of the producing formation, the oil may be displaced by gas or water injected for that purpose. The mechanism of the displacement is in no manner different from that previously described. If gas is injected into the structural crest of a reservoir a gas-cap drive is created; if water is injected into or around the lower edges of a reservoir a water drive results that resembles natural water drive except in the relation between the reservoir pressure and the rate of influx of water.

Geometric differences arise, however, when gas or water, instead of being injected at one or the other of the reservoir boundaries, is injected within the reservoir through wells interspersed among the producing wells. When injection is carried out in such fashion the reservoir is in effect subdivided into a number of separate producing segments, in each of which the displacement of oil is simultaneously taking place, and the shapes of which are fixed by the well patterns employed.

Because of the natural tendency of gas, oil, and water to segregate according to their relative densities, gas will tend to migrate up dip and water will tend to migrate down dip regardless of where injected. Accordingly, the injected fluids can be retained within the intended reservoir segments only when conditions are unfavorable to their migration under the force of gravity. Pattern injections are usually confined, therefore, to reservoirs having low structural relief or nearly horizontal bedding, or low to moderate permeability, or when production and injection rates are so high that fluid movements in the reservoir are dominated by the pressure gradients rather than by the force of gravity.

Pattern injections are commonly employed in secondary-recovery operations to obtain additional oil from reservoirs depleted by dissolved-gas drive. They have seldom been used as a primary oil-recovery method. In a reservoir whose physical structure is suitable for use of gas-cap drive or water drive under conditions where the force of gravity may be employed to increase the flushing efficiency, pattern injections cannot be expected to yield as high a degree of ultimate oil recovery as either natural or artificial gas-cap or water drive properly controlled to flush the entire reservoir progressively.

Chapter VI

EFFICIENT OPERATION OF PETROLEUM RESERVOIRS

Part One . . . OIL RESERVOIRS

APPLICATION OF FUNDAMENTALS

A basic working knowledge of fluid mechanics and of the specific processes by which oil is recovered is an essential preliminary, but efficient recovery of oil requires far more than fundamental concepts. The real task lies in applying such knowledge to each reservoir, in recognizing its specific characteristics, in choosing the process best suited, and in operating that particular reservoir so that the maximum possible ultimate quantity of oil may be recovered. Generalities are helpful only to the extent that they lead to recognition of the possibility of effecting improvements, and to appreciation of the need for quantitative technical analysis.

It is not practical to attempt in this volume a detailed treatment of all of the elements involved in an engineering study of a reservoir or pool or all of the techniques involved in the evaluation and control of different operating procedures. Some of the more important requirements may be recognized, however, through review of the considerations involved and the methods employed in application of the known fundamentals to the recovery of oil from a whole pool as distinct from their application to isolated segments of a pool.

The Reservoir as the Producing Unit

It is apparent from the descriptions of the mechanisms of displacement involved in dissolved-gas drive on the one hand and gas-cap or water drive on the other that there is a basic difference between the former and the latter two that is primarily responsible for the differences in ultimate recovery to which they lead. In the dissolved-gas drive, gas is released from solution everywhere throughout the reservoir. It occupies a part of all of the pore space. It cannot be excluded from wells by any manner of well completion or well operation, and there is no way to avoid its dissipation. When the gas is exhausted there no longer remains a source of reservoir pressure to drive further quantities of oil into the wells. As a result, the reservoir is depleted long before the recoverable oil content is exhausted. The inefficiency is the direct result of the inability to retain within the reservoir the gas released from solution. When there is no longer within the reservoir any source of pressure to drive additional oil to the wells, the production process must cease, regardless of the residual oil content.

On the other hand, with a gas-cap drive or with a water drive there does not occur simultaneously throughout the reservoir a depletion of the oil from all of the pore space, but a selective and progressive displacement of oil from successive portions of the reservoir. In the case of gas-cap drive, the lower regions of the reservoir remain saturated with oil until the entire reservoir has been invaded by the expanding gas. This condition makes it possible to complete wells selectively to produce oil only, and thus to retain within the reservoir until the oil is substantially exhausted the expanding gas that is the source of the reservoir pressure. Similarly, with water drive, the water advancing from the edge or bottom progressively displaces and removes oil from the pore space adjacent to the advancing water front and moves the oil upward. Here, also, it is possible by proper well location and by proper well completion to produce oil selectively and to exclude the invading water, if necessary, in such manner as to retain within the reservoir a source of driving pressure until the entire reservoir has been thoroughly flushed by water and substantially exhausted of its oil content.

The difference between these two extremes has been called by some the difference between a *depletion* process, as exemplified by dissolved-gas drive, and a *displacement* process, as exemplified by the other two. In the sense that all three are displacement processes the essential difference might be considered to reside primarily in the fact that with the dissolved-gas drive the depletion occurs simultaneously throughout the reservoir, whereas under the other two, displacement occurs progressively through the reservoir from one region to another. In other words, gas-cap and water drive are processes that of necessity must lead to a migration of oil from one portion of the reservoir to another. They might, therefore, be called migration processes. It is obvious that with the dissolved-gas drive mechanism, if wells are spaced uniformly throughout the reservoir, the characteristics of the reservoir itself as an entity have little bearing, in that the oil production by a particular well is influenced largely by the formation conditions in the region tributary to that well, without particular regard to what may happen at a more remote location where similar events are taking place. In the case of gas-cap drive or water drive, on the other hand, since oil must be moved from one portion of an entire reservoir to another portion of that entire reservoir if the process is to be used effectively, it is the reservoir rather than the well that becomes the basic unit of production and the behavior of which must be controlled.

THE VOLUMETRIC BALANCE

Of fundamental importance to control of an oil reservoir is the volumetric balance concept; it is this concept that makes possible quantitative interpretation of the behavior. The principle involved is really nothing more than recognition that in a petroleum reservoir of fixed total void space the expansion of the fluids originally present is quantitatively equal to the net fluid withdrawal.

The volumetric balance is used through numerical computations based on substituting into a simple algebraic equation* the known withdrawals from a reservoir and the known unit or total expansions of the original oil and free gas, and solving for such unknown quantities as the amount of water influx, the original amount of oil, or the original amount of free gas contained within the reservoir. The calculations require accurate information on the original and subsequent reservoir pressure, on the amount of oil, gas, and water produced, and on the volumetric behavior of the reservoir fluids.

The volumetric balance is a powerful tool; through its use it is possible to determine from adequate production history the size of a reservoir, its possible total fluid content, the degree of rearrangement of fluids that may be taking place, the amount of water that has entered at any particular time, and, under certain conditions, the degree of recovery efficiency. Computations based on this con-

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*The volumetric balance may be expressed algebraically by the equation

$$Nx + Gy = W - Z$$

where N is the original content of reservoir oil.

x is the cumulative expansion of a barrel of reservoir oil and its dissolved gas to any particular reservoir pressure.

G is the original content of free gas in the reservoir.

y is the cumulative expansion of a barrel of free gas to any particular reservoir pressure.

W is the sum of the cumulative withdrawals of oil, free gas, and water corrected to the volume they would occupy in the reservoir at the prevailing reservoir pressure at the time of consideration.

Z is the total cumulative influx of oil, water, and gas into the reservoir up to the time under consideration, measured at the reservoir temperature and pressure prevailing.

cept make it possible, for example, to determine not only whether a reservoir is operating under dissolved-gas drive, gas-cap drive, or water drive, but to determine quantitatively at any time the amount of oil that has been produced by each mechanism, and to predict into the future the degree to which the reservoir will continue to operate under each of these drives under any given set of probable future conditions. Through computations based upon this approach it is possible early in the life of a pool to detect conditions that will lead ultimately to inefficient recovery and to take steps to modify the operating conditions in such fashion as to bring about increased efficiency.

As the whole volumetric balance approach requires the use of operating data, it is obvious that the results obtained can be no better than the data employed in the calculations. For this reason, one of the prime requirements for efficient ultimate oil recovery is adequate and complete information systematically obtained on the reservoir pressures, including the original pressure, and on the production of oil, gas, and water from each well within the reservoir.

Identification and Prediction of Recovery Mechanisms

Frequently, an oil pool is operated without deliberate selection of a recovery mechanism. Instead, the natural reactions of the reservoir to the oil production set the conditions. It becomes important under such circumstances to determine as early as possible in the life of the pool the exact and specific processes taking place within the reservoir and, insofar as possible, whether the existing natural mechanisms are efficiently or inefficiently effecting the oil recovery. If adequate information is available, quantitative identification of the recovery mechanisms is possible through analysis by the volumetric balance. If the available information is not adequate for quantitative analysis, certain readily distinguishable differences in behavior of a reservoir under dissolved-gas drive, gas-cap drive, and water drive make it possible to identify qualitatively the dominant mechanism.

Qualitative Detection of Dominant Drive

The principal differences that may be relied upon to distinguish between the different drives are as follows:

1. *The reservoir pressure.*

Under the dissolved-gas drive the reservoir pressure declines continuously toward atmospheric; the decline is substantially proportional to the cumulative volumetric withdrawal and is relatively independent of the rate of production.

If a natural gas-cap drive is the dominant mechanism the reservoir pressure will usually decline at a moderate rate; the larger the free gas cap, the less the decline per unit of production. If the gas cap is large and free gas is not dissipated, the reservoir pressure may remain at a fairly high level until the gas cap has completely invaded the oil zone.

If water drive is the dominant mechanism the reservoir pressure should remain at a reasonably high level throughout the production process.

2. *The gas-oil ratio.*

Under a dissolved-gas drive the gas-oil ratio usually commences at a low level, declines slightly, rises to a maximum, and thereafter falls in all wells regardless of where or how they are completed.

Under a gas-cap drive the gas-oil ratio rises continuously in upstructure wells but, if reservoir pressure has been sustained, remains relatively constant in downstructure wells until they have been reached by the advancing gas front. After the advancing gas front has invaded the entire oil zone, all wells will have extremely high gas-oil ratios.

If water drive is the dominant mechanism and the reservoir pressure has been maintained at a high level, the gas-oil ratio will remain at or close to the dissolved ratio in all wells.

3. *Water production.*

If dissolved-gas drive is the dominant mechanism by virtue of physical barriers preventing water influx, water production should be negligible.

Water production should also be negligible in a sealed reservoir dominated by gas-cap drive.

If water drive is the dominant mechanism downstructure wells should produce water at an early date; their water production should continuously increase, and wells progressively upstructure should go to water as the water advance continues.

Quantitative Analysis

Although the differences mentioned are adequate to characterize the dominant mechanism provided information is available on the reservoir pressures, on the gas-oil ratios of individual wells, and on the history of the water production of individual wells, this minimum of information is by no means adequate to determine the specific degree to which any one mechanism is operative, or to determine quantitatively over the life of the reservoir the portion of the ultimate recovery attributable to each mechanism. In order to determine such quantitative factors it is necessary to use the volumetric balance and to calculate for the entire reservoir and for each significant portion thereof the exact manner and degree of depletion and the mechanism responsible for it. Such calculations are essential to prediction of the conditions that will prevail in the future.

The need for such calculations may be made evident through consideration, for example, of a reservoir containing both saturated oil and a free gas cap, and located in a highly permeable formation filled with water throughout a large portion of its extent, with no permeability barriers to prevent water influx. The reservoir pressure will be reduced to some extent as a result of oil production no matter how slowly the oil is withdrawn. The opening to production of the first well sets in motion the following chain of events: The reservoir pressure declines in the immediate neighborhood of the producing well, permitting a certain amount of gas to escape from solution in the reservoir. To this extent the process begins as a dissolved-gas drive. As production continues, the region affected by the producing well continuously enlarges, and the reservoir pressure is reduced in the oil zone at distances progressively further removed from the producing well. Within a short time such pressure reduction is transmitted to both the gas-oil contact and the water-oil contact. As soon as the pressure reduction reaches the gas-oil contact the free gas present in the upstructure portion of the reservoir begins to expand and to invade the oil zone. Concurrently, the reduction in pressure at the water-oil interface allows the reservoir. There will shortly be occurring, simultaneously, dissolved-gas drive in all or part of the reservoir, expansion of the gas cap into part of the oil zone, and influx of water into the lower portion of the reservoir. Thus, dissolved-gas drive, gas-cap drive, and water drive will be taking place at the same time in different portions of the same reservoir.

The amount of oil produced by each mechanism may be determined through volumetric balance calculations if the following information is available:

1. The total withdrawals from the reservoir of each fluid, oil, expansion of the water and influx of water from the aquifer into gas, and water.

2. Physical measurements that will make possible the correction to reservoir volumes of the measured surface volumes of the produced fluids.

3. The expansibility of the reservoir gas and the reservoir oil.

4. The original and subsequent reservoir pressures.

5. The original volumes of oil and of free gas contained in the reservoir.

The computation of the amount of oil recovered from the reservoir through each mechanism is made as follows:

1. The amount of reservoir oil ejected by the release of dissolved gas is equal to the original reservoir oil content multiplied by the average total unit expansion of the oil-gas mixture as determined from the decline of the reservoir pressure from the original saturation pressure.

2. The amount of reservoir oil ejected by expansion of the gas cap is equal to the net volume of such expansion, which is equal to the original volume of free gas multiplied by its unit expansion as determined from the average reservoir pressure decline in the free gas zone, less the reservoir volume of any free gas produced.

3. The amount of reservoir oil ejected by water influx is equal to the total reservoir withdrawals of gas and oil less that quantity already accounted for by dissolved gas and by gas-cap expansion.

Prediction

In the absence of any other information it is not possible from determination of the mechanisms responsible for the past production of a reservoir to determine which of the operative drives will become dominant over the remainder of the life of the pool. The question that must be answered in order to predict the future dominant drive is the future degree of reservoir pressure decline. It is obvious that if the reservoir pressure declines but slightly and thereafter stabilizes at a value not significantly lower than the original pressure, expansion of the free gas cap will cease; similarly, the release of dissolved gas from the reservoir oil will cease, and both the dissolved-gas drive and the gas-cap drive will cease to function in that reservoir. Such a stabilization of reservoir pressure can take place only if a stage is reached at which the entire volume of reservoir withdrawals is currently replaced by an equivalent volume of water influx. It becomes apparent that prediction of the reservoir pressure requires that there be available a quantitative relationship between the decline of reservoir pressure and the volume or rate of water influx that will be caused thereby.

Given adequate geological information on the reservoir and its surrounding regions in terms of the thickness, continuity, and permeability of the producing formation throughout both its oil-bearing and water-bearing portions, it is possible to approximate from fundamental considerations the rate of water influx that will be induced by a given differential between the reservoir pressure and the initial pressure in the aquifer. However, such approximations are by no means adequate for quantitative prediction of the behavior of the reservoir. Quantitative predictions require calculations based upon the observed operating characteristics of the reservoir in question and can be no better than the basic information employed in them. It is essential for such purpose that there be available precise information on the original reservoir pressure, equally precise information on the reservoir pressure at later dates, and exact information on the amount of water influx that has taken place in the past under the observed pressure differentials. It is possible to measure the reservoir pressure with subsurface pressure gauges developed for that purpose. However, it is not possible by direct observation to determine either the rate of water influx or the total quantity of water influx. These items can be determined only through use of volumetric balance computations.

The cumulative influx of water into a reservoir at any time may be calculated in the manner previously outlined. Computation of the rate of water influx for a specific pressure differential requires computations of the cumulative influx at various stages of depletion of the reservoir. It is possible, then, from adequate production history and from basic mathematical equations that describe the flow of water under an expansion process, to determine from the actual reservoir performance the necessary coefficients of the equation in such manner as to permit prediction of the future relationship between the decline of reservoir pressure and the rate of water influx.

The approach outlined requires information on the original oil content of the reservoir and the original gas content of the reservoir. Such information can be determined only from systematically planned observation during the development of the pool, including adequate coring, logging, and testing. If adequate information regarding the original oil and gas content of the reservoir is not available, the volumetric balance calculations may still be employed through a process of trial and error solutions to determine the amount of water influx. Such an approach usually requires a longer operating history before reliable predictions are possible.

It is apparent that a certain amount of production history on a reservoir is required before a quantitative prediction can be made. This makes it impossible during the very early life of a pool to make more than qualitative predictions as to the probable recovery processes. The more precise and reliable the available information, the earlier such estimates may be made, and the more reliance may be placed in them. With adequate data it is frequently possible after some 5 to 10 per cent of the original oil content of a reservoir has been produced to determine the quantitative relationships involved with sufficient accuracy to permit proper control thereafter of the efficiency of recovery.

CONTROL OF RESERVOIR PERFORMANCE

It would be an idle pastime indeed to determine the exact manner and degree by which the oil in each particular reservoir is being recovered if it were not possible for the operators to exert some manner of control to modify the existing action of the reservoir in such direction as to result in higher ultimate oil recovery. It is obvious, of course, that there are a large number of factors over which the operators can exert no possible control. Among these are the original geology of the oil reservoir and its surroundings, including the texture of the producing formation, the original reservoir contents of oil, gas, and water, and the characteristics of those fluids. On the other hand, it has been seen that there are available at least three possible methods of recovering the oil, each different from the others and some more efficient than the others. The question whether the operators can control the performance of the reservoir involves the question whether it is possible, first, to substitute a more efficient drive for a less efficient one and, second, to control the efficiency of the chosen drive to yield the maximum return. *Reduced to its simplest form, the question is basically whether it is possible to substitute an efficient gas-cap drive or water drive for a dissolved-gas drive in an oil reservoir.*

The answer to the first part of the question is affirmative, for the simple reason that it is frequently possible to inject produced gas to create a gas cap, and, except under very unusual circumstances, it is possible to inject water, if necessary, into the edges of a reservoir to bring about a water drive. The basic question, therefore, is not so much whether the operators can bring about more efficient operation, but which operation should be chosen and how that operation can be made as efficient as possible. The earlier a choice is made between whether to operate with an expanding gas cap or with a water drive, the lower will be the total development and operating costs and the greater will be the ultimate net return. The ultimate recovery of oil may also be increased. Among the reasons are: the arrangement, location, and manner of completion of the wells must be different for efficient control of a gas-cap drive than for efficient control of a water drive, and under either drive it is usually desirable to conduct the operation at a high level of reservoir pressure to avoid dominance of the depletion by dissolved-gas drive. This means starting the operation as early in the life of a pool as possible, before the reservoir pressure has declined seriously.

The ultimate efficiency will be dependent upon the degree to which it is possible to make the advancing gas or water invade the entire reservoir and upon the uniformity with which the advancing gas or water performs its function in displacing or flushing the oil content of the reservoir rock as the front advances. Two aspects of this uniformity are important: first, the front must advance with an over-all surface sufficiently regular to permit selective production of oil and to avoid dissipation of the advancing fluid, and, second, the advancing front must have displaced oil not merely from selected portions of the reservoir rock but, insofar as possible, to the same degree from all portions of the reservoir rock behind the advancing gas or water. When consideration is given to the extreme differences in the texture encountered within a single oil reservoir it is obvious that the latter requirement is a very difficult one.

The basic requirements for proper control of an oil reservoir may be summarized as follows:

1. An efficient dominant mechanism for the recovery of oil must be chosen. This mechanism may be natural, if reservoir conditions are favorable; it may be supplemented by injection of gas or water; or it may be created entirely through injection of gas or water.

2. The dominant mechanism must consist in the progressive advance of gas or water from one boundary or region of the reservoir progressively through the entire reservoir. Migration of oil ahead of the advancing gas or water is an essential feature of the process.

3. A sharp demarcation must at all times be preserved between

that portion of the reservoir invaded by the displacing gas or water and that portion not yet invaded.

4. The boundary between the invaded and uninvaded portions of the reservoir must at all times be reasonably uniform.

5. The residual oil saturation throughout the invaded portion of the reservoir must be reduced to a uniformly low value regardless of variations of the texture of the producing formation. There must be no trapping or by-passing of highly oil-saturated zones or sections behind the advancing gas or water front.

6. Excessive dissipation of gas or water must be avoided.

7. Wells must be so located and so completed as to permit the entire reservoir to be effectively flushed by the advancing gas or water.

8. The reservoir pressure must be maintained throughout the duration of the recovery process at a sufficiently high level to prevent excessive release of gas from solution.

The Maximum Efficient Rate

The requirements for efficient recovery of the oil from a reservoir are not taken care of by chance; they may be fulfilled only through careful and deliberate action by the producers. Experience has shown that one of the most essential factors in meeting these requirements is control of the rate of production. Excessive rates of withdrawal lead to rapid decline of reservoir pressure, to release of dissolved gas, to irregularity of the boundary between invaded and non-invaded sections of the reservoir, to dissipation of gas and water, to trapping and by-passing of oil, and, in extreme cases, to complete loss of demarcation between the invaded and non-invaded portions of the reservoir, with dominance of the entire recovery by inefficient dissolved-gas drive. Each of these effects of excessive withdrawal rates reduces the ultimate recovery of oil.

Operation of a reservoir at an infinitesimally low rate of oil production would not in itself assure efficient recovery unless other necessary conditions were met. However, if all other conditions are fulfilled, the ultimate oil recovery from most pools is directly dependent on the rate of production. The nature of this dependence is such that for each reservoir there is for the chosen dominant mechanism a maximum rate of production that will permit reasonable fulfillment of the basic requirements for efficient recovery. Rates lower than such maximum may permit still higher ultimate oil recovery, but once the rate is sufficiently low to permit the basic requirements to be met, the incremental ultimate recovery obtainable through further reduction of the rate of production may be insufficient to warrant the additional deferment of a return and the additional operating expenses that would result from a prolongation of the operation. A rate of production so low as to yield no return would obviously be uneconomic, of no advantage to the operators, and of no ultimate benefit. However, increase of the rate of production beyond the maximum commensurate with efficient recovery will usually lead to rapidly increasing loss of ultimate recovery. From these considerations there has developed the concept of the *maximum efficient rate* of production, often referred to as the M.E.R. For each particular reservoir it is the rate which if exceeded would lead to avoidable underground waste through loss of ultimate oil recovery.

The M.E.R. is not an invariant characteristic of a reservoir, but is dependent on the recovery mechanism employed as well as on the physical nature of the reservoir, its surroundings, and its contained fluids. For the same reservoir it will be different for one recovery mechanism than for another, and for the same mechanism the M.E.R. may vary with the degree of depletion. The M.E.R. is determinable through engineering study provided adequate geologic and operating information on the reservoir is available.

M.E.R. Under Dissolved-Gas Drive

It will be recalled that when the dominant recovery mechanism is dissolved-gas drive the only displacing agent is gas released from solution, no other source of gas and no water being employed. The process is inefficient because the dissolved gas is released everywhere throughout the reservoir, is not segregated, and cannot be prevented from escaping along with the oil through the producing wells.

It seems anomalous to consider the efficient rate at which to carry out an inefficient process; for this reason, much confusion has arisen regarding application of the M.E.R. concept to reservoirs producing by dissolved-gas drive. The application can perhaps be understood if careful distinction is made on the basis of the reason for dominance of the recovery in a particular reservoir by a process of dissolved-gas drive and if proper attention is paid to other factors that may influence the recovery efficiency.

Such distinction might be made by consideration of three classes of dissolved-gas-drive reservoirs, as follows:

Class 1. Those reservoirs in which there is potentially available free gas or water that might, under different operating conditions, be employed to change the dominant recovery mechanism.

Class 2. Those reservoirs in which no free gas or water is potentially available but whose physical properties and fluid characteristics are favorable for segregation of gas within the reservoir.

Class 3. Those reservoirs having no displacing fluid potentially available other than dissolved gas and whose characteristics are so unfavorable as to permit no reasonable modification of the efficiency through control of the rate of production.

M.E.R. of Class 1 Dissolved-Gas-Drive Pools—Pools falling in Class 1 are those that initially contain free gas in sufficient quantity to provide a gas-cap drive, or into which sufficient influx of water could take place to provide a water drive if the operating conditions were properly modified. Class 1 pools most frequently operate by a dissolved-gas drive as a direct result of one or more of the following causes, all of which constitute improper reservoir control:

1. Dissipation of the free gas through production of gas-cap wells or upstructure wells having high gas-oil ratios.

2. Dissipation of the water through excessive production of water by edge wells.

3. Excessive rate of production of oil. The rate of production is excessive and is the direct cause of dominance of the recovery by dissolved-gas drive if it is such as to deplete the oil content substantially faster than the oil can be replaced by migration ahead of an expanding gas cap or advancing water. Such excessive rate is often brought about by too great a number of wells, the aggregate production of which, if each is permitted to produce at sufficient rate to assure profitable operation, is more than the proper amount for the reservoir.

Many of the older fields now exhausted were produced by dissolved-gas drive as a direct result of the causes enumerated. Such operation is now considered to be wasteful in that the inefficiency can be avoided through proper control.

The M.E.R. of a Class 1 reservoir is not a rate below which the dissolved-gas mechanism will itself become efficient, but a rate that will permit a more efficient mechanism to replace it. The M.E.R. is therefore the M.E.R. of the substituting mechanism. The factors involved might be better understood through a specific example.

Consider a reservoir with the following characteristics:

Original recoverable oil content: 20 million barrels
Area: 2,000 acres
Number of wells: 200
Original reservoir pressure: 2,000 pounds per square inch
Original volume of free gas in gas cap: 10 million barrels
Reservoir volume factor: 1.30 barrel of reservoir oil to a barrel of surface oil

It will be presumed that each well is producing at a rate of 50 barrels a day. The total production is 10,000 barrels a day of oil and 4 million cubic feet a day of free gas through high-ratio wells. This production is causing a reservoir pressure decline of 300 pounds per square inch a year.

The following facts will be presumed to have been determined by suitable engineering studies:

1. The natural availability of water influx into the reservoir would be 4,000 barrels a day at a reservoir pressure of 1,600 pounds per square inch.

2. To provide efficient flushing of the oil from the formation by water the rate of advance of water through the oil zone should not exceed 4,000 barrels a day.

3. To prevent excessive release of gas from solution in the reservoir oil the reservoir pressure should not be permitted to decline below 1,600 pounds per square inch.

Under the presumed circumstances the M.E.R. of this reservoir under water-drive operation would not exceed 4,000 barrels a day of reservoir oil. With correction for shrinkage of the oil in passing from the reservoir to the surface, this M.E.R. would be 3,100 barrels a day of stock-tank oil. Efficient operation under water drive would impose other requirements: primarily, the immediate reduction or elimination of the production of free gas and the future avoidance of dissipation of water.

It will be presumed, also, that efficient operation of this reservoir by an expanding gas cap would be possible at a rate of 2,000 barrels a day of oil as measured at the surface. The M.E.R. under that operation would then be 2,000 barrels a day. Such operation would also impose other requirements. Because of the natural influx of water the mechanism would be dominated by water drive, and gas-cap expansion would cease if the reservoir were produced at a rate of 2,000 barrels a day. Operation under gas-cap drive would therefore require deliberate production through edge wells of all water entering the reservoir; the closing in of gas wells and high-ratio wells would be a basic requirement.

It will be presumed further that for this particular reservoir, under the conditions outlined, the ultimate recoveries obtainable by the three possible mechanisms would be as follows:

Dissolved-gas drive: 6 million barrels
Gas-cap drive: 13 million barrels
Water drive: 17 million barrels

From the standpoint of purely physical considerations, the reservoir picked for illustration has two M.E.R.'s, one if it is to be operated by water drive, the other if it is to be operated by gas-cap drive. Because of the obvious advantage of the water drive in this instance, the water-drive M.E.R. might be considered as a practical matter to be the M.E.R.

Whether it is actually feasible to operate the reservoir by water drive involves other considerations, both administrative and economic. These considerations are dealt with in later chapters.

Confusion may arise, however, between *technical determination* of the M.E.R. and the practical *feasibility* of operation under a particular mechanism at a rate not exceeding the M.E.R. In the particular reservoir chosen for illustration, if serious depletion has not already occurred through dissolved-gas drive, if the ownership of leases and state regulations are such as to make feasible the closing in of gas wells and high-ratio wells and the avoidance of dissipation of water without unreasonable damage to the equities of the various lease owners, and if the costs are such that operation can be profitable at the required reduced rate of production, then the M.E.R. has real and tangible meaning. If the reservoir is already so far depleted by dissolved-gas drive that reestablishment of segregation between the oil zone and the water-invaded zone is not physically possible, or if the distribution of ownership and the regulations are such that the other essentials for operation under a controlled water drive cannot be provided, then it may seem meaningless to determine a hypothetical efficient rate for a process that cannot be employed. Even under the latter conditions, however, determination of the M.E.R. may be useful in pointing the way to improvement. Cooperative action on the part of all the operators may often make feasible a production process that cannot be carried on independently by individual producers.

M.E.R. of Class 2 Dissolved-Gas-Drive Pools—A dissolved-gas-drive pool in Class 2 is one in which the physical structure and texture of the reservoir rock and the viscosity of the oil are such that there is no inherent condition within the reservoir that would prevent the employment of gas or water in an efficient manner as a displacing fluid, but which does not have free gas or water naturally available and is producing by dissolved-gas drive because the sole displacement agent naturally available is the dissolved gas.

Potentially, there are several ways in which such a reservoir might be operated. One method would be to inject the produced gas into the crest of the structure to create artificially an expanding gas cap. If such an operation were adopted the M.E.R. would then be the M.E.R. under conditions of gas-cap drive.

A second alternative would be to inject water through properly located wells and to produce the reservoir by a water-flooding process. If such an operation were adopted the M.E.R. would then be the M.E.R. for the water-flooding mechanism employed.

A third alternative would be to use only the dissolved gas naturally available within the reservoir, but to impose such operating conditions as to bring about substantial improvement in the recovery efficiency. It is obvious that under this alternative there is only one way in which the ultimate oil recovery might be increased. That would be to retain within the reservoir the gas that has escaped from solution, so that instead of being dissipated it would displace additional oil.

In order to understand the manner in which such a modification might be brought about, it is necessary to explore in detail into the exact mechanism of the flow of gas within the reservoir. It will be recalled from the basic equation of fluid mechanics presented in Chapter V that the motion of an element of oil or gas within a formation is brought about by two forces; one force is the pressure gradient, the other is the force of gravity. The direction of motion of each fluid is governed by the local resultant of these two forces acting on each fluid. If the flow is horizontal and is in a formation having no vertical permeability the force of gravity has no component in the direction of flow. If, on the other hand, the formation is not horizontal, but lies in an inclined position, which is the usual situation in an oil reservoir, then the force of gravity does have a component in the direction of flow. If the rate of production of each well in an inclined reservoir is reduced to a sufficiently low value so that throughout most of the area of the reservoir the movement of oil is brought about by gravity rather than by the pressure gradient, then within that portion of the reservoir free gas will move up dip instead of toward the wells. If the released gas can be segregated in the upper portion of the reservoir instead of escaping through the wells it can then be retained to displace additional oil. Such segregation of released gas would remove the basic cause of the inefficiency of the dissolved-gas drive as a recovery mechanism, and the resultant increase in ultimate oil recovery would be directly attributable to reduction of the rate of oil production.

In this type of reservoir, then, the M.E.R. is the rate that will permit the gas released from solution to be retained within the reservoir by a process of selective segregation. Such segregation of gas would, of course, be of no avail if wells were uniformly spaced throughout the reservoir and were completed in such manner that the liberated gas in its attempt to migrate upstructure would be intercepted by producing wells and thereby be lost from the reservoir. The other requirements for efficient operation are similar in all respects to those for efficient operation under an expanding gas-cap drive. A basic necessity would be the closing in of wells completed in a structurally high position.

Secondary gas caps formed by the release and segregation of dissolved gas have been observed in many instances, but selective production through downstructure wells under a dissolved-gas drive for the deliberate purpose of bringing about a gravity segregation of the released gas has seldom been practiced except in the very late stages of depletion of a pool after the reservoir pressure has declined substantially to atmospheric and production has declined to a very low level. When such a condition has been reached most of the wells have usually been plugged and abandoned; in many instances gravity has then become the dominant reservoir force causing oil to migrate to structurally low wells, which may thereafter continue to produce substantial quantities of oil for a long time. Usually, such a process takes place only after almost the entire supply of reservoir gas has been dissipated, and the action of gravity is more one of rearrangement of the existing gas and oil within the reservoir than in the selective segregation of gas newly released from solution. Nevertheless, this action of gravity in pools depleted by a dissolved-gas drive has been responsible for the production of important quantities of oil from some reservoirs. An outstanding example is the oil production during the later stages from the Oklahoma City field.

M.E.R. of Class 3 Dissolved-Gas-Drive Pools—A dissolved-gas-drive reservoir in Class 3 is one in which the characteristics of the reservoir and its fluids are so unfavorable that reduction of the rate of oil production would have no appreciable effect on the ultimate oil recovery. Conditions that might place a reservoir in this category would be very low formation permeability, high viscosity of the oil, extreme lenticularity or irregularity of the producing formation, and horizontal formation bedding of such character as to prevent vertical movement of fluids.

It has not been conclusively demonstrated that reduction in the rate of production can bring about any improvement in the recovery efficiency in a pool that has no free gas cap and no potential water drive and that has physical conditions that prevent any segregation of fluids by gravity. It is doubtful that a pool of this sort has any natural M.E.R.

Since the only natural mechanism available in this type of pool is unmodified dissolved-gas drive, the recovery efficiency will be low as a direct and inevitable result of circumstances beyond the operators' control. Secondary-recovery operations following depletion by dissolved-gas drive have shown that in many reservoirs of this type it is possible to produce additional oil profitably by injection of gas or water into the producing formation. There is no reason to defer operations of that sort when they are applicable, and certain physical advantages and economies may sometimes be obtained through employment of artificial gas drive or water drive during the early stages of production. However, the rate of production of the pool under such circumstances is dependent in large measure on the number and location of injection wells and the availability of the injected gas or water, so that the proper rate is largely a matter of economics. The M.E.R. of a pool operated in this manner is not a unique characteristic of the reservoir, or even of the recovery mechanism, but depends on the particular conditions under which the recovery mechanism is employed.

M.E.R. Under Gas-Cap Drive

Dominance of the oil recovery by the mechanism of gas-cap drive requires continuous maintenance throughout the recovery process of distinct segregation between an enlarging gas-invaded zone containing reduced oil saturation, and a shrinking oil zone containing high oil saturation. Since comparatively little oil is usually produced after the invading free gas has completely penetrated the oil zone, the ultimate oil recovery is very nearly proportional to the degree of oil desaturation of the reservoir at the time the advancing gas front has reached the lowermost wells.

The recovery efficiency by this mechanism is very sensitive to the rate of oil production. Excessively high rate would cause rapid encroachment of the free gas throughout the oil zone with a relatively low displacement efficiency. Thereafter, it would be impossible to maintain segregation of free gas, and the entire free gas content of the reservoir would be dissipated, resulting in lowered reservoir pressure and dominance of the recovery by a process of dissolved-gas drive.

One of the chief reasons for this dependence of the ultimate oil recovery on the rate of production is that gas is not an effective oil-displacement agent. Another reason is that in the absence of any restraining factors encroachment of free gas through the oil zone would take place selectively through only the most permeable channels, leaving the oil undisplaced in most of the remainder of the formation. At high rate of production the pressure gradients caused by the flow of oil dominate the fluid movements in the reservoir, and the ultimate oil recovery is fixed largely by the noncontrollable items such as the formation texture and the original reservoir fluid characteristics. Under such conditions gas-cap drive has little advantage over dissolved-gas drive unless very large quantities of free gas are available.

The only manner in which a high degree of desaturation of the reservoir may be accomplished with a gas-cap drive is through dominance of all fluid movements in the reservoir by the force of gravity instead of by pressure gradients. In any reservoir the component of gravity in the direction of flow is fixed by the inclination of the formation and cannot be increased. The only manner in which this fixed force may be made to dominate the flow is for the pressure gradients to be suppressed to comparatively low magnitude. This required suppression may be accomplished through reduction of the rate of production of oil.

An efficient rate of production under gas-cap drive must be a rate such that gravity will dominate the oil flow to a sufficient extent to maintain continuously an advancing gas front behind which the oil saturation throughout the formation will be reduced to a satisfactorily low value, in regions of low permeability as well as in regions of high permeability. This requirement amounts to conducting the recovery at such a rate that oil migrates into the lower portion of the reservoir and maintains the oil saturation therein by gravity drainage instead of being compelled to migrate by expanding gas forcing its way into the oil zone in response to a pressure differential between high pressure in the gas cap and low pressure in the oil zone. The actual pressure in all parts of the oil zone must remain higher than the pressure in the gas cap, and the free gas must be relegated to the passive role of merely expanding to fill space vacated by the downwardly migrating oil. The chief function of the gas is to maintain the pressure level at which the gravity drainage proceeds; the higher the pressure the lower is the oil viscosity and the more rapid the drainage.

At sufficiently low rate of production a process of this sort is capable of yielding very high recovery efficiency. Determination of the M.E.R. requires quantitative calculation of the relationship between the rate of production and the amount of residual oil saturation in all parts of the reservoir at various successive stages of depletion. The distribution of the residual oil saturation at any stage is a crucial item. Such a calculation must be based on adequate factual data on the texture and permeability of the reservoir rock and on their variation throughout the producing formation. There must also be taken into account the fact that as the oil saturation declines in the upper portion of the reservoir the permeability to oil becomes less and the drainage rate slower.

The M.E.R. under this type of operation is directly dependent on the permeability of the formation, the permeability distribution, and the fluidity of the oil. Since in most reservoirs the permeability vertically or transverse to bedding is not effective except over short distances, the flow is predominately parallel to the formation strata, and the M.E.R. is also dependent on the angle of the dip of the formation. High oil recoveries are usually attainable at a reasonable production rate only when all of these conditions are favorable. Since high fluidity or low viscosity of the oil is desirable, there is an advantage to conducting the drainage at the highest possible level of reservoir pressure. Maintenance of pressure is often assisted through return of all produced gas to the crest of the structure. Efficient recovery by this mechanism requires, also, the progressive closing in of the upstructure wells as they go to gas, and the selective production of oil from wells completed in the lowermost portions of the reservoir.

M.E.R. Under Water Drive

Unlike the conditions under dissolved-gas drive and gas-cap drive, wherein the primary reason for reducing the rate of production is to allow gravity to become the dominant force in the reservoir, other factors become important when consideration is given to the effects in a water-drive reservoir of variations in the rate of production. The first condition required for a water drive is that the net water influx into a reservoir be substantially equal volumetrically to the oil withdrawal. Water can move into a reservoir only as the result of a pressure differential between the aquifer and the oil zone; for any given reservoir configuration and formation permeability the rate at which water can invade the reservoir at any time is directly proportional to the pressure differential between the aquifer and the reservoir. The faster the rate of oil production the higher must be the pressure differential between the aquifer and the reservoir for the water influx to keep pace with the oil withdrawal. Unless the water influx does keep pace, other mechanisms come into play in the displacement of the reservoir oil, and water drive may cease to be the dominant mechanism.

Determination of the proper rate of production of a water-drive pool requires, first, a determination of the proper level or range of reservoir pressure to be maintained throughout the production history, and, second, calculation of the rate of influx of water at the predetermined level of reservoir pressure. The proper reservoir pressure is usually taken to be one that will not permit dissolved gas to be released in sufficient quantity to build up within the oil zone a free gas saturation large enough to allow flow of the liberated gas. Because of the expansible nature of reservoir fluids and of the water in the aquifer, adjustments of reservoir pressure do not take place instantaneously with adjustments of withdrawal rates; as a practical matter, it is usually necessary to determine the level to which the reservoir pressure will be allowed to decline eventually over the life of the production process. Determination of the efficient rate of production of a water-drive pool requires basically, therefore, a quantitative relationship between the reservoir pressure and the rate of water influx. As was pointed out previously, such a relationship may be calculated through the use of the volumetric balance concept, together with adequate information on reservoir pressures and oil, water, and gas production.

As in the case of the gas-cap drive, it is also necessary to provide reasonably uniform encroachment of the water-oil interface and, to the maximum extent possible, uniform displacement or flushing of the oil behind that interface in the regions invaded by water. Control of the uniformity of the advancing water front, as in the case of the advancing gas front, is dependent upon the balance between the component of gravity in the direction of flow and the pressure gradients induced by flow. Since the density contrast between oil and water is less than the density contrast between oil and gas, control of the uniformity of an advancing water front is more difficult than control of the uniformity of an advancing gas front and requires that the pressure gradients induced by the flow be even less in the case of water drive than in the case of gas-cap drive. Another requirement of the M.E.R. in a water-drive pool, therefore, is that the rate of production be sufficiently low, considering the specific texture and permeability distribution of the reservoir rock, to allow gravity to regulate the level of the advancing front. Partially offsetting this requirement is that water is a more effective displacement agent than is gas and will more thoroughly flush the oil content of a formation even when the advancing front is permitted to become somewhat irregular.

Another very important effect is present in a reservoir operated under a water-drive mechanism. Because of variations in permeability of the reservoir rock there is a natural tendency for the flow of both water and oil to take place primarily in the more permeable channels and to take place reluctantly, if at all, in the less permeable portions of the formation. Unless it is possible to make the water invade and flush the oil from the less permeable portions of the rock the oil therein will be left unrecovered after water has advanced entirely through the reservoir and production has ceased. Fortunately, most reservoir rocks are preferentially wetted by water in the presence of oil; the capillary forces set up by rock texture and interfacial tension are such as to cause water selectively to enter the finer interstices and regions of low permeability and to eject the oil therefrom into the more permeable sections of the formation. These capillary forces are very small and cannot cause rapid fluid movements except over extremely short distances. If an entire sand section is to be flushed uniformly by water the rate of advance of the water must be slow enough to permit the water selectively to eject the oil from the less permeable into the more permeable channels where it may be flushed upstructure by the advancing water front. Unless such action takes place concurrently with the advance of the water front the oil will not be recovered from sections of relatively low permeability. Once the water front has invaded the entire reservoir the water production will reach a very high level, and the operation will eventually be abandoned because of economic limitations. Any additional oil that thereafter might be ejected from the smaller interstices into the more permeable channels would remain entrapped by water and be unrecovered. It becomes very important, therefore, in the efficient use of water drive to restrict the rate of water advance to that at which the water can uniformly and to a high degree displace the oil from all portions of the reservoir rock, including those channels of low permeability.

Thus, control of the rate of production in a water-drive pool has three aspects, as follows: first, control of the rate of oil withdrawal to such a degree that the oil may be volumetrically replaced by water at a desirable level of reservoir pressure; second, control of the rate of withdrawal to such degree that the force of gravity may keep reasonably uniform the advancing water-oil interface; third, control of the rate of advance of the water to such degree that the water may concurrently with the advance of the interface selectively eject the oil from the less permeable channels into the more permeable channels in order that the entire reservoir may be flushed uniformly while the water-oil interface is advancing. Unless all of these conditions are met, the most efficient production from a water-drive pool is not realized.

THE FUNCTION OF WELLS AND WELL SPACING

Wells have very important functions in the control of an oil reservoir. Not only are they the conduits through which oil and gas are produced, but they provide access to the reservoir for other purposes. It is through the wells that much of the information essential to proper reservoir control is obtained, and it is through the location, manner of completion, and production of the wells that fluid movements within a reservoir are controlled. Since the cost of drilling and equipping the wells is usually the major part of the total cost of developing an oil pool, the number of wells directly affects the economics of the operation and often thereby affects the operating practices.

Prior to the advent of efficient oil-recovery practices and the attendant recognition of the need for controlling an oil reservoir as a unit, the attention of operators was focused entirely on the well. Under unregulated competitive production it was found that those leases that had wells drilled first, or that had the most wells, or that had wells of the highest capacity, produced more oil ultimately than leases so developed as to have lesser productive capacity. Efforts were directed to completion of wells in such fashion as to have the highest possible potential when producing wide open, and much attention was devoted to analysis of the rate of decline of the production. Because oil and gas migrate freely in petroleum reservoirs in response to pressure gradients caused by production, those areas that produced oil most rapidly drained oil and gas from less intensively developed areas and thus obtained higher ultimate recovery for each surface acre. It became well recognized that within a common pool the ultimate recovery from different leases varied in proportion to their respective well densities. Unfortunately, the reasons underlying the observed facts were not as well understood as the facts themselves, and many acquired the impression that the number of wells drilled affects in some manner the efficiency with which reservoir energy is used to produce oil. This supposition led in turn to the entirely unsupported further conclusion that the oil recovery from an entire reservoir is also directly dependent on the well density. Such a conclusion was a far cry from the observed fact that in a common reservoir properties drilled to different well densities produce ultimately relatively more or less oil than each other.

Much confusion still exists, not only in the minds of laymen, but even in the technical literature, regarding the effects of well density on ultimate oil recovery. Although the reasons for the confusion are to a large extent historical, even so, some present confusion and controversy arise from failure to analyze properly the specific functions of wells in relation to the basic mechanics of reservoir depletion under the various types of oil recovery processes.

The first use of the wells, and in the long run one of the most important, is to obtain adequate geologic information. The mere drilling of wells does not provide such information; it must be obtained by coring, logging, and testing, and the number of wells drilled is not a measure of the adequacy of the information obtained. Nevertheless, it is obvious that a sufficient number must be drilled and must be cored and logged to provide specific information in adequate detail on the exact outline of the reservoir, its texture, the distribution of its texture and other characteristics, both laterally and vertically, and the total amount of oil, gas, and water contained. The specific number of wells required to provide such information cannot be expressed by any general rule, as the requirements vary between extremely wide limits, depending upon the nature of the reservoir. For any specific reservoir it is usually possible to determine an acceptable minimum of information, and to drill, core, and log a sufficient number of wells to provide that information. On a highly faulted piercement salt dome, where the producing formations may be broken both laterally and vertically into many disconnected segments, it may become necessary in some instances to have wells very close together even to provide assurance that each reservoir be identified. Where production is obtained from blanket sands rather uniformly deposited over large areas and gently arched without evidence of structural irregularities, conditions may be found where very low well density is adequate to provide the necessary reservoir information.

It is probable that in most reservoirs many more wells are drilled than are needed to obtain adequate geologic information. The problem is to obtain the proper information from strategically located wells.

From the standpoint of their direct bearing on the ultimate oil recovery from a reservoir, it is necessary to consider separately the effects of the wells under different recovery practices.

If a reservoir is to be produced dominantly by dissolved-gas drive under conditions that permit no gravity segregation of the released gas, the available information indicates that the number of wells is important primarily in the resultant effect upon the possible oil withdrawal rate, and in most of such reservoirs has very little specific effect upon the ultimate recovery if the wells are produced to a sufficiently low economic limit to provide material exhaustion of the pressure throughout the oil reservoir. An adequate number of wells to bring about such exhaustion of pressure at the time production ceases is the basic requirement. The degree of pressure exhaustion obtained may be measured directly in the producing wells; for the portions of the reservoir tributary to the wells it may be calculated from the permeability of the formation, the viscosity of the oil, and the rate of production at the time the wells are abandoned. Unless the formation permeability is extremely low or the oil viscosity unusually high, the average reservoir pressure at abandonment does not usually differ materially from that measured in a well after it has been closed in for one to two days. It is important to note that with this type of operation it is not necessary to speculate regarding the proper well density. From tests on the wells and from suitable geologic information it is possible to determine by straightforward calculations by well known techniques the rate of production, the final pressure distribution within the reservoir, and, from the pressure distribution, the ultimate production to be expected with any particular well density.

If a reservoir is to be produced by unmodified dissolved-gas drive the location of the wells is relatively unimportant. However, if advantage is to be taken of gravitational effects it is desirable that the producing wells be located only in the lower portions of the reservoir and that wells not be produced in upstructure locations. The usual development, whereby wells are drilled throughout the reservoir, is not conducive to efficient use of gravity to improve the oil recovery through segregation and retention of gas within the reservoir.

Since the mechanism with a gas-cap drive is one of continuous displacement of oil from the upper to the lower portion of a reservoir, it is obvious that, regardless of the number of wells, most of the oil must eventually travel into the downstructure position and be produced selectively from that portion of the reservoir. Since efficient operation requires the early abandonment or closing in of wells at intermediate positions, the important consideration is that properly completed wells be available to produce the oil from the lowermost reaches of the reservoir. It is the geometry of the reservoir and the location of the wells with respect to such geometry that is important, rather than the number of wells. If, in a reservoir produced by a gas-cap drive, there were 100 uniformly spaced wells, 90 of which had to be abandoned before the oil recovery process was complete, the remaining 10 wells would be the only ones that could exert any important influence upon the ultimate oil recovery. The intermediate wells might be very useful for observation purposes, but once they had been passed by the invading gas front they would cease to function as producers, and the ultimate oil recovery would be dependent on the degree to which the gas could be made to invade the lowermost portions of the reservoir without being prematurely dissipated.

Similarly, in a water-drive field, wherein the water must eventually encroach throughout the entire reservoir and reach the uppermost sections, it is again the geometry of the reservoir and the specific location of wells in respect thereto that will ultimately govern the efficiency. Intermediate wells might serve no function that is ultimately important except in the role of observation wells.

A specific factor frequently overlooked in consideration of the reservoir geometry is that the bedding in most producing formations forces the fluids to travel in a direction primarily parallel to the bedding planes rather than transverse. Vertical flow across bedding planes is often restricted or totally impossible. When reference is made to the reservoir geometry in terms of upstructure and downstructure positions these terms relate specifically to upstructure and downstructure positions within each stratum of the producing formation within a reservoir. For example, if the reservoir trap is formed by truncation and deposition of an impermeable barrier over a bedded sandstone there might well be a multiplicity of upstructure terminal positions for various portions and members of that sandstone. The geometrical requirements for adequate recovery by water drive would not be met by a single row of wells or rim of wells in the upstructure position. In most reservoirs the geometrical configurations are such as to require at least a wide band of wells for either upstructure or downstructure position, so located and so spaced as to permit complete and selective displacement in each stratum by the action of invading gas or water.

One other factor must also be taken into account in consideration of the number of wells required to deplete a reservoir adequately. For any particular reservoir, once the proper recovery mechanism has been decided upon, it is possible to determine quantitatively a proper maximum total rate of withdrawal of reservoir oil. If it is desired to withdraw such maximum it is then necessary to have at least a sufficient number of wells to provide that rate of withdrawal. A sufficient number of wells means not only the number of wells physically capable of producing that volume when wide open, but capable of producing that volume of oil without locally causing excessive disturbances of reservoir pressure that would cause local variation of the dominant recovery mechanism or would induce excessive irregularities in the shape of the advancing gas or water front through such factors as channeling, fingering, or coning. The required number of wells depends in part on the texture of the producing formation and the pressure differential required to bring about the flow of oil into a well.

When an adequate number of wells have been provided to meet the geometric structural considerations necessary for the thorough flushing of the reservoir by water or by gas, and when a sufficient number have been provided in such proper locations to permit a maximum efficient rate of withdrawal from the reservoir without the creation of unfavorable local conditions in the immediate neighborhood of the wells, the reservoir then contains an adequate total number of producing wells. Once this adequate number have been provided and are properly completed it is extremely doubtful that additional producing wells serve any necessary purpose or have any material effect on the ultimate oil recovery.

The indications are that in most oil reservoirs developed to date the total number of wells drilled has substantially exceeded the number actually required to obtain efficient ultimate recovery.

Well Completion

The methods necessary for proper completion of a well depend on the character of the reservoir rock, the depth of the well, and the distribution and properties of the reservoir fluids, as well as on the geometry of the reservoir. As a mechanical unit, the bore hole must be extended into or through the producing formation and must be protected with casing, with facilities for control of the pressure and of the flow and for the exclusion of water and gas. At times the characteristics of the reservoir or the specific effects of the fluids employed in drilling may be such that flow of reservoir fluids into the well bore can take place only with difficulty, so that it may be necessary to provide improved access through the employment of acid or explosives or other techniques to open up the reservoir rock.

An important element in the completion of the well is that it be properly cased and cemented in such manner as to exclude from the producing interval oil, gas, or water from strata other than those from which it is intended to produce. Since reservoir control is dependent to a large extent on knowing accurately the water, oil, and gas production from individual wells, ample precautions must be taken to insure that the fluids produced from a well actually come from the reservoir under consideration and not from other sources.

Since the function of the well is to drain the oil from a reservoir, it is essential that it be physically able to do so. A reservoir with average vertical permeability approximating that in a horizontal direction could conceivably be drained through wells completed with only a limited section of the formation open. However, if the wells are completed with casing set entirely through the reservoir rock, with the annular space between the pipe and the rock filled with cement, and with the pipe and cement perforated to permit entry of oil, any impermeable layers that may subdivide the formation should continue to be effective, and, unless each separate portion of the producing formation is eventually opened, little or no recovery may be obtained from some parts of the formation. The entire oil-yielding section in reservoir rocks that contain numerous breaks must be opened eventually to wells properly located to drain each subdivision of the reservoir.

Of particular importance in relation to efficient depletion of a reservoir by gas-cap or water drive is that the wells be so completed as to permit proper control of the manner of advance of the gas or water. Since the complexities created through the variations of porosity, permeability, and other factors within a single reservoir are sufficient to tax severely the resourcefulness of the operator, it is usually undesirable to complicate the problem further by adding all the variables in a second reservoir to those in the first. As a result, it is not considered good practice to produce separate reservoirs simultaneously through the same well if it is practical to maintain their isolation. However, even though the desirability of restricting the production of each well to a single reservoir may be recognized, such restriction may not be practical in some oil fields where thin multiple reservoirs overlie each other in close proximity.

Even within a single reservoir, if it is composed of a multiplicity of separate producing formation members interspersed with barriers to vertical flow, it may be very difficult to control the movement of gas or water simultaneously through more than one such member. It may also be impossible by direct observation to determine the degree to which gas or water has advanced within any particular member if they are all open at once into the same well bore. Although all members must eventually be produced in order to provide complete flushing of the reservoir, it is desirable in producing with either a gas-cap or water drive to produce selectively, insofar as is possible or practical, from only one identifiable formation member at a time.

As a practical matter, future control is usually more readily provided, and the required work-overs of the wells are cheaper if, in a water-drive pool, the production of the reservoir is conducted in a progressive fashion by selective flushing of the lowermost members first, followed by progressive flushing thereafter of the upper members, until the entire reservoir has been flooded. By opening a single well to a single formation member it is possible to identify immediately the source of the water when water invades that well and to close off the water when the water production has become excessive at that particular spot. Such a well may then be recompleted in a higher member and the process repeated until the entire reservoir has been thoroughly flushed by water. Similarly, a producing well in a field operated by a gas-cap drive may be drilled through the producing formation but at first be completed selectively in the uppermost oil-bearing member of the formation and, as that member goes to gas, be successively recompleted in lower strata. Through such a process of selective completion it is usually possible to maintain throughout the producing life of a pool adequate control over the movement of either water or gas and to prevent their premature dissipation.

Standards of Efficiency

It is helpful to the control of any operation to have certain standards as objectives and to have indicators or measuring devices that inform the operator while the process is going on whether the conditions are such as to assure reasonable attainment of the desired result. Efficient oil recovery would be difficult enough even if it were possible to observe directly at all times the conditions in the reservoir; it is made doubly difficult by the fact that direct inspection is physically impossible. The conditions prevailing at any time within the reservoir must be inferred or deduced from what is known of the character of the reservoir and its originally contained fluids, and from such limited measurements as may be made within a well bore or on the fluids produced by a well. Since the available observational procedures are severely limited in number, those few that may be employed must be exploited to the highest possible degree.

Recoverable Oil

It is not a simple matter even to provide a standard of efficiency for the operation of an oil reservoir. It would seem offhand that if a reservoir contained a known quantity of oil the percentage of that oil ultimately recovered by the time of abandonment would be the proper measure, with 100% recovery representing perfect efficiency. Unfortunately, complete oil removal from a porous rock is not physically possible by any conventional displacement process now employed, and percentage recovery of the oil originally contained is not a direct measure of displacement efficiency. The term *recoverable oil,* representing the oil that may be physically displaced from the rock, has often been employed to get around this difficulty. This concept also leads to ambiguity.

The available facts indicate that when a porous rock containing oil is flushed with unlimited quantities of either gas or water the permeability to oil declines toward zero at a final oil saturation that is not zero. It is presumed that at some stage the remaining oil is agglomerated by capillary forces into isolated droplets or disconnected filaments that no longer provide continuous paths for further oil flow. The remaining oil is not recoverable by a displacement process. However, the exact amount of unrecoverable oil is not an invariant characteristic of the particular oil and the particular porous rock but is dependent on the displacement fluid employed. It is not possible, therefore, to compare directly the efficiency of gas drive, water drive, or a combination in the same reservoir on the basis of percentage recovery of the recoverable oil. Such a standard is quite unsatisfactory for other reasons if comparisons are to be made between different reservoirs. For example, in two reservoirs employing water drive, if the physically undisplaceable oil represents in each case an oil saturation of 10% of the pore space, but one reservoir initially contains 10% connate water and the other 50% connate water, an ultimate recovery in each such that the remaining oil saturation is reduced to 20% of the pore space would represent in one case 87½% of the recoverable oil and in the other case only 75%. Percentage recovery of the total original oil content would similarly be different, being 78% and 60% in the two cases, respectively.

Residual Oil Saturation

A useful measure that avoids some of the objectionable features of percentage comparisons is the residual oil saturation in the reservoir, expressed as a fraction or a percentage of the pore space. It provides a reasonably direct index to the absolute efficiency, not only at abandonment, but during the course of the recovery. If the average oil saturation of a reservoir at abandonment is low the recovery may be judged to be efficient; furthermore, the residual oil saturation in the invaded portion of the formation provides a measure at any time of the efficiency with which a gas-cap drive or water drive is effecting the oil displacement.

Efficiency Indexes

The procedures by which the efficiency of a recovery process may be inferred or determined during the course of the operation involve both qualitative deductions and quantitative determinations. The indexes are the reservoir pressure, the gas-oil ratio, and the water-oil ratio. These indexes may be used as follows:

1. Reservoir pressure.

Through volumetric balance calculations the average reservoir pressure, along with other data, may be used to determine the recovery mechanism in a manner outlined previously. Such a determination provides a measure of the recovery efficiency only to the extent that one recovery mechanism may be presumed to be more efficient than another. It does not, alone, provide a measure of the specific efficiency of the recovery process.

The pressure difference between closed-in and flowing conditions in each well, and the pressures in individual wells throughout the reservoir provide direct measures of the pressure gradients involved in the oil flow. Comparison of the pressure gradients with the components of the force of gravity indicates the probable resultant effect on the uniformity of an advancing gas-oil or water-oil interface and whether or not the conditions are conducive to efficient use of the prevailing recovery mechanism.

Irregularities of the reservoir pressure indicate regions of locally unfavorable reservoir characteristics, such as areas of low permeability that may not become flushed thoroughly by advancing gas or water, or they may reflect excessive localization and concentration of withdrawals, which may lead to irregularity of advance of gas or water and loss of recovery efficiency.

In general, continuous rapid decline of average reservoir pressure, and excessive irregularity of reservoir pressure are directly indicative of conditions that will lead to inefficient ultimate recovery unless they are corrected.

2. Gas-oil ratio.

An average gas-oil ratio for an entire reservoir appreciably exceeding the dissolved ratio is always indicative of inefficient operation, unless the produced gas is returned to the reservoir.

An average gas-oil ratio equal to or less than the original dissolved ratio may be indicative of proper operation, but does not, alone, provide assurance of efficient flushing by gas-cap or water drive.

Differences of gas-oil ratio among different wells may be indicative of either efficient or inefficient operation, depending upon the recovery mechanism. If the recovery process is dissolved-gas drive, increase of gas-oil ratio of upstructure wells is a direct reflection of gravitational segregation within the reservoir; provided the high-ratio wells are closed in to avoid dissipation of the segregating gas, the segregation indicates modification of the dissolved-gas drive in a direction leading to increased oil recovery. If the reservoir is operated by gas-cap or water drive, erratic gas-oil ratios of individual wells may reflect local areas of low permeability or of excessively concentrated production that will lead to reduced ultimate recovery.

High gas-oil ratio of wells ahead of the average position of the gas-oil contact in a reservoir operated by gas-cap drive shows irregular advance of the gas-oil interface and serves as a direct warning that the rate of production of oil is excessive, either locally or in the reservoir as a whole.

The gas-oil ratios of wells already passed by the advancing gas-oil interface in a reservoir operated by gas-cap drive provide a measure of the degree of oil desaturation in the upper portion of the reservoir. Although wells behind the gas-oil interface should not be produced unless the gas is returned to the reservoir, they may serve a useful function as observation wells if they are maintained in a producible condition for periodic gas-oil ratio measurements.

In a reservoir whose pressure is maintained substantially constant by water drive, any production of gas in excess of the dissolved ratio is directly indicative of shrinkage of the gas cap and of migration of oil into space previously occupied by gas. Gas-cap shrinkage always leads to loss of ultimate oil recovery because of the impossibility of recovering all of the oil from the invaded portion of the formation. Gas-cap shrinkage may also take place in a reservoir whose pressure is only partially maintained by water drive, but under such a condition the amount of shrinkage can be determined only by use of the volumetric balance.

3. Water production.

Premature production of water in wells ahead of the average position of an advancing water-oil interface shows irregular advance of the interface. Local irregularities may be caused by variations of the permeability of the formation or by improper well completion, or they may be aggravated thereby, but in any event they indicate conditions that will lead to inefficient recovery. They serve as a warning that the rate of production of the wells in question is excessive in relation to the proximity of the water front and the formation texture, or that the rate of production of the reservoir as a whole is excessive.

The water-oil ratios of wells already passed by the water front provide a measure of the amount of oil remaining unflushed behind the advancing interface.

Quantitative Determination of Flushing Efficiency

Two methods may be employed to determine at any stage of the recovery in a reservoir operated by either gas-cap or water drive the degree of flushing efficiency being obtained. One method involves use of the volumetric balance; the other is to drill wells for the specific purpose of seeking such information. The latter approach requires that the test wells be cored completely through the entire productive formation in sections of the reservoir already flushed by advancing gas or water to determine the residual oil saturation and its distribution. It is quite difficult to obtain accurate results by the latter method.

From adequate geologic information obtained during development it is possible to determine the distribution of the formation thickness and of the original oil content throughout the reservoir. From measurements of the production of gas and water of individual wells it is possible at any stage of the recovery to determine the position of the advancing gas or water front. By use of the volumetric balance the total amount of oil displaced by the advancing gas or water may be calculated. By combining the information from these three sources the amount of oil recovered and the amount of oil left behind the advancing interface may be calculated. Direct determination in this manner of the specific recovery efficiency at any stage of the operation makes it possible to determine whether or not the rate of advance of gas or water is sufficiently slow to bring about satisfactorily complete flushing, and makes it possible to control the operation continuously in such manner as to yield the highest oil recovery practically attainable.

Part Two . . . GAS RESERVOIRS

RECOVERY PROCESSES FOR GAS

The recovery of natural gas from an underground formation is much less complicated than is the recovery of oil. Since gas, unlike liquid crude oil or water, is a highly expansible fluid, it may be recovered from a porous rock by the direct and simple procedure of allowing it to escape by expansion into a well. If, for certain reasons, maintenance of reservoir pressure is desirable, gas may be displaced by natural or artificial water drive in the same manner as oil is displaced. Pressure depletion and water drive are the only two processes employed for the recovery of gas. However, a third process, known as cycling, is often used to recover the heavier hydrocarbons contained in the reservoir gas in the vapor state. Cycling consists in displacement of wet gas from a formation by injection of dry gas. It is most often used in gas-condensate reservoirs where reduction of pressure would cause condensation and loss of heavier hydrocarbons. After completion of a cycling operation, the gas remaining in a reservoir may be recovered by either expansion or water drive.

Recovery by Expansion

The expansion characteristics of a gas are quantitatively described by certain natural laws, according to which the volume of a given weight of gas is inversely proportional to the absolute pressure and directly proportional to the absolute temperature. These two laws are usually grouped together as the perfect gas law. They quantitatively describe the behavior of most gases at low pressure, but may be erroneous by a factor of 10% to 40% at pressures and temperatures commonly encountered in deeper gas reservoirs. Accordingly, there has come into widespread use a correction factor, commonly referred to as the deviation factor, which is introduced to express by an exact equation the relationship between the volume and the temperature and pressure of a unit quantity of gas.

The deviation factor may be experimentally determined for the particular gas in question at the temperatures and pressures of interest, or it may be calculated from the experimentally determined composition.

In a closed gas reservoir into which there is no influx of water during depletion, the amount of gas recoverable from a unit of pore space may be computed directly from the initial pressure and the expected abandonment pressure. The abandonment pressure is governed primarily by economic factors and by the permeability of the reservoir. The process of production consists merely in opening one or more wells into the porous strata initially occupied by gas and withdrawing gas from the wells. As under this process one well will eventually deplete the gas in any continuously permeable stratum in which it is completed, the number of wells drilled in a gas reservoir is governed almost entirely by such factors as the rate at which gas is to be withdrawn, the yield per acre, the conditions of subdivision of ownership within the reservoir, and other economic factors.

The efficiency of the recovery of gas by the pressure-depletion or expansion process is quite high. Neglecting the deviations from the perfect gas law, the gas recovery to be expected from a reservoir initially having a pressure of 1,000 pounds per square inch and abandoned at an average reservoir pressure of 100 pounds per square inch would be of the order of 90% of the original gas in place. Ultimate recoveries of 90% or more of the gas are commonly obtained by this process from reservoirs having reasonable formation permeability. Low recovery from a gas reservoir is obtained only when the formation permeability is so low that it is not possible to sustain economic rates of production except at high reservoir pressure. In areas where the price of gas at the wellhead is high, recovery is sometimes increased by employment of vacuum at the wells to reduce the reservoir pressure to a low value.

Recovery by Water Drive

In any subterranean reservoir connected through continuously permeable channels with an aquifer, water will invade the reservoir to some extent as a result of any decline of reservoir pressure. The rate of such water influx is dependent primarily upon the permeability of the strata through which the water must flow. Thus, whether or not a gas reservoir can be operated under natural water drive is dependent more on the geologic conditions encountered than on the choice of the operator. However, if geologic conditions are favorable to water influx in large quantity with moderate reservoir pressure reduction, it then lies within the control of the operator whether or not to employ such water influx as the dominant recovery agency. In order to save compression for delivery of gas to a pipe line, or in order to maintain high rate of yield per well, the operator may elect to maintain the reservoir pressure at a high level throughout the depletion process. This may be done through restriction of the rate of withdrawal of gas to that rate at which the gas will be volumetrically replaced by water influx at the desired level of reservoir pressure. If the pressure is thus maintained, gas is flushed from the outer boundaries of the reservoir and is driven toward the wells. Operation of a gas reservoir under this mechanism is similar in all respects to operation of an oil reservoir by the same mechanism. Proper location of the wells with respect to the structural geometry of the reservoir is important, as is, also, control of the water advance in such manner as to provide uniformity and completeness of flushing.

Since displacement by water is not required for efficient recovery of gas from a reservoir, artificial water drive is rarely, if ever, employed for gas recovery.

PROCESSES FOR RECOVERY OF CONDENSATE

Although the recovery of gas from a reservoir is very simple and a high recovery efficiency is almost always possible, this simplicity does not necessarily carry over to the recovery of condensate from a gas-condensate reservoir. If the nature of the reservoir gas is such that reduction of pressure will cause a large part of its condensate content to condense to liquid within the formation the expansion process is not applicable to recovery of the condensed liquid. In fact, the liquid saturation that results from such condensation is always so low that there exists no method whereby the condensed liquid can be displaced from a reservoir in the liquid state to give a high degree of liquid recovery efficiency. Usually, the reservoir saturation of condensed liquid is so low that none of the liquid at all can be displaced as liquid.

The physical impossibility of displacing as liquid the heavier hydrocarbons that may condense within a reservoir leaves no alternative for their recovery but to displace them from the reservoir in the gaseous or vapor state. In principle, there would appear to be available two approaches to vapor-phase displacement for recovery of condensate. One would be to displace the wet gas with its vapor-phase condensate without allowing reduction of reservoir pressure; the other would be to revaporize the condensed liquid into gas at very low reservoir pressure.

Unfortunately, the latter method is not applicable in most condensate reservoirs. In those reservoirs in which reduction of pressure can cause a serious amount of condensation, the condensate almost always contains a high proportion of hydrocarbons so heavy that their volatility at low pressure is too low for their recovery by revaporization to be feasible. Their volatility is appreciable only at high pressure. As a practical matter, therefore, that part of the condensate content of a gas that pressure reduction will cause to condense within a reservoir can be recovered only by displacing the wet gas from the reservoir at high pressure.

Proper exploitation of a condensate reservoir therefore requires the following:

1. Determination of the amount and composition of the liquid that will condense within the reservoir as a result of pressure reduction. These can be determined by the methods outlined in Chapter IV.

2. Determination of the most feasible recovery method in the light of the factual information regarding the behavior of the reservoir gas, the physical characteristics and size of the reservoir, and the applicable economic factors.

Three courses are open, as follows:

1. To produce the reservoir by a simple expansion process, recovering the condensate that leaves the reservoir in the vapor phase with the produced gas and abandoning that which condenses within the reservoir.

2. To recover the gas with its vapor-phase condensate with the reservoir pressure maintained by water drive.

3. To cycle the reservoir for condensate recovery prior to withdrawal of gas for other disposition.

Each of these processes has certain advantages and certain limitations. Proper choice for a particular reservoir requires that there be available adequate factual information on the characteristics of the reservoir and its contained fluid.

Condensate Recovery by Expansion

The recovery of condensate by the simple process of withdrawing gas from the reservoir and allowing the reservoir pressure to decline is not necessarily inefficient; in fact, in many reservoirs it may yield a higher ultimate recovery of condensate than any other process. If the characteristics of the producing formation are such that the reservoir pressure can be reduced to a reasonably low value the ultimate recovery of gas from a deep reservoir is often in the range of 85% to 95% of the original gas content. In many reservoirs the amount of condensation caused by pressure reduction will not exceed 10% to 30% of the original condensate content of the reservoir gas. The combined effect of the very high gas recovery and moderate loss by condensation is such that in many reservoirs an ultimate recovery of 60% to 85% of the original condensate content is obtainable by simple production of the gas and removal of the condensate in suitable surface recovery equipment.

In very deep reservoirs with very high pressure and very rich reservoir gas the condensation is usually more severe. In such reservoirs the amount of condensate recoverable by simply producing the gas from the reservoir may be as low as 40%; it is quite unusual, however, for the condensate recovery by this process to be less than 50%. The process is often suitable in reservoirs having original pressure less than 3,500 pounds per square inch and containing gas only moderately rich in condensate. Pressure depletion cannot yield efficient recovery of the heavier hydrocarbons from a reservoir containing a fluid of such composition that its critical temperature and critical pressure are near the reservoir temperature and pressure.

MAINTENANCE OF PRESSURE BY WATER DRIVE

If the physical characteristics of a reservoir are such that through control of the rate of withdrawal of gas the pressure can be maintained by water drive within a few hundred pounds a square inch of the dew-point pressure of the reservoir gas, condensation within the reservoir can usually be kept to less than 10% of the original condensate content of the gas. The degree of ultimate recovery of condensate by water drive depends primarily on the thoroughness with which water can flush gas from the formation. The low density and low viscosity of gas are conducive to a higher degree of flushing efficiency than is obtained with oil. Under favorable circumstances, with a properly controlled operation, the residual gas content of a reservoir may be reduced to as low as 15% to 20% saturation. In a reservoir containing initially 20% connate water and 80% gas saturation, flushing by water to an average residual gas saturation of 15% at a reservoir pressure 10% below its original value would yield an ultimate recovery of approximately 83% of the original reservoir gas content. The ultimate condensate recovery would be approximately 75% if the reservoir gas were produced at 90% of its original richness.

In order to obtain high ultimate recovery by this process it is necessary to invoke all of the controls required for efficient oil recovery by water drive.

CYCLING

In a cycling operation the wet gas in the reservoir is produced, is stripped of its condensate in suitable surface equipment, and the stripped dry gas is compressed and returned to the producing formation to maintain the pressure and to prevent condensation. The wet gas in the formation is displaced toward the producing wells by the injected dry gas. The ultimate condensate recovery obtainable depends, as in all flushing processes, on the completeness with which the entire reservoir can be flushed by the time the operation reaches its economic limit.

Mechanics of Cycling

During the cycling process the injected dry gas does not mix to any important extent with the wet reservoir gas but displaces it. The process is somewhat similar to the displacement of oil by water, except that complete displacement is effected in that part of the pore space invaded by the dry gas. Since the wet gas and dry gas are completely miscible and have very nearly the same physical properties, gravity and surface tension play no part in the recovery process, and the degree of displacement is not influenced by the rate. The displacement itself is a simple and straightforward flushing and is essentially completed at the moving boundary between wet and dry gas.

Because no gravity and surface tension effects are present, the over-all efficiency of the displacement is dictated entirely by the geometry of the system and the physical texture of the reservoir rock. The displacing dry gas will invade the various accessible portions of the formation at a rate proportional to their permeability. Although flushing will be complete in any invaded section of the formation, the formation will not be uniformly flushed, because the degree of invasion will vary with the rock texture. The operator can exert no control over the uniformity of the displacement. The only factors the operator can control are the pattern of injection and producing wells and the relative amounts of gas withdrawn from or injected into each.

The condensate recovery obtainable by the cycling process is very dependent on the degree of uniformity of the producing formation. If the formation is reasonably suitable for cycling it is usually possible to displace from 65% to 75% of the wet gas by the time the produced gas becomes too lean to support continued operation. If the producing formation is lenticular, or has great variation of permeability vertically or laterally, cycling is usually not feasible at all and would yield very low recovery, for the injected dry gas would flow through the most permeable strata to the producing wells and, by dilution, would decrease the condensate yield of the produced gas to a low value long before the wet gas could be displaced from the less permeable portions of the reservoir.

If, following a cycling operation, gas is withdrawn from a reservoir for market and the produced gas is stripped of its remaining condensate content, the total ultimate recovery of condensate by both cycling and gas withdrawal may be quite high.

Chapter VII

SECONDARY RECOVERY

ARTIFICIAL STIMULATION OF RECOVERY

The technology of oil recovery has now become sufficiently well advanced that it should be possible in the future to obtain relatively high ultimate recoveries from most of the pools now known and those yet to be discovered. The question naturally arises, however, as to the possible recovery of additional oil from pools already depleted or substantially depleted by less efficient methods prior to the development and application of improved recovery practices. Can such pools be reopened and be produced again with improved techniques to obtain a second harvest of oil? Fortunately, the answer is, at least to some extent, affirmative. As a matter of fact, secondary-recovery operations were inaugurated in some pools long before the present improved recovery procedures were known. The experience gained and the information acquired through these operations contributed materially to the development of efficient methods applicable to newer pools.

Before the development of modern recovery techniques it was the common practice to produce wells at capacity or wide open. Under such uncontrolled operations not only was much oil left in the reservoir, but it was usual for a pool to yield the major part of its ultimate recovery during a relatively short period of "flush" production. This period was usually followed by a prolonged interval characterized by low rates of production from the individual wells. This latter period has been referred to as the "stripper" stage. A national survey indicated that approximately 311,000, or 69%, of the nearly 450,000 producing oil wells in the United States on Jan. 1, 1950, were stripper wells. These wells produced an average of 3 barrels a day each during 1949.*

An eventual decline of the rate of production of each well is to be expected in any reservoir. However, in an efficiently operated reservoir most of the recoverable oil is displaced during the period of flush production, and the stripper stage is usually of short duration. In a reservoir operated without benefit of a properly controlled and

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*Data from API *Petroleum Facts and Figures,* 9th edition, 1950, p. 144. Authority: Interstate Oil Compact Commission.

efficient recovery method the stripper stage begins while there still remains in the reservoir a substantial quantity of recoverable oil. Even after a prolonged period of stripper production much recoverable oil may remain in the reservoir after the rate of production has declined to so low a value that it will no longer support the operation and the wells are abandoned.

The most prevalent cause of inefficient ultimate recovery is production by dissolved-gas drive. In many of the older pools the characteristics of the reservoir were such that no other recovery mechanism was naturally available. In others, dissolved-gas drive was the direct result of excessively high rates of production during the flush stage.

In many pools operated under dissolved-gas drive it has been possible to stimulate the production during the stripper stage, or even to rejuvenate production after depletion, by injection of gas or water into the reservoir through selected wells. The injected gas or water displaces oil from the vicinity of the injection well and creates a pressure gradient that causes the displaced oil to flow toward the producing wells. Pronounced increases in the rate of oil production have often been observed when the injection of gas or water was begun during the stripper stage, and substantial increases in the ultimate oil recovery have been obtained in a number of older pools.

There is, of course, no reason to delay injection of gas or water into a reservoir if such injection is required to bring about efficient recovery. In fact, as will be shown in Chapter VIII, substantial advantages can often be gained by employment of such injection at an early stage if the characteristics of the pool are suitable for gas drive or water drive and if injection is required. This fact has given rise to some confusion in terminology, because operations essentially identical in character have been identified by different terms, depending primarily on the stage in the life of a pool at which injection of gas or water is first employed.

Regardless of when it is started, the injection of gas or water into an oil reservoir for the purpose of driving oil toward the producing wells results in a gas drive or a water drive. When the injection has been started at an early stage, before the reservoir pressure has declined greatly, it has usually been called "pressure maintenance" or "artificial pressure maintenance," because the injection retards the decline of reservoir pressure. When the injection has been started after the reservoir pressure has declined to a low level and a pool is in the stripper stage, or has been depleted, it has usually been called a *secondary-recovery* operation. Thus, a secondary-recovery operation differs from artificial pressure maintenance only in the time of application.

In the sense that injection of gas or water may bring about an increase in the ultimate recovery of oil over and above that to be expected otherwise, secondary recovery has been considered by some to include the oil recovered by any operation in which one or more wells are employed for injection of fluids into a reservoir, regardless of the stage in the life of a pool such stimulation is employed. In this volume the term is employed in its narrower historical sense to refer more particularly to the recovery of oil left unrecovered by the original or "primary" operation. A definition that may better fill this more restricted use of the expression is as follows: *Secondary recovery* is the recovery of oil by the injection of fluids into a reservoir for the purpose of displacing additional oil after the pressure in the reservoir has declined to a small fraction of its original value.

SELECTION OF POOLS FOR SECONDARY RECOVERY

It is known that, in the aggregate, tremendous quantities of oil still remain in the depleted pools in the United States. Since the location of this oil is known, the risks normally associated with exploration for new oil reserves are absent in secondary recovery. Nevertheless, the oil remaining in most of these pools is probably not recoverable by techniques now known and employed. Accordingly, substantial risks are also encountered in secondary-recovery operations, and proper selection of a pool for secondary recovery is extremely important.

Not all depleted pools are suitable for secondary-recovery operations by techniques now known. Improper primary production practices may have caused irreparable damage to the reservoir. Even though a reservoir may be physically unharmed, the remaining oil content may not be sufficient to support a profitable recovery operation. Furthermore, the oil left in a reservoir after the pressure has declined to a low value may be both more difficult and more expensive to recover than an equivalent amount of oil in a virgin reservoir of comparable physical characteristics.

Among the items that may adversely affect secondary recovery in comparison with primary recovery the following may be listed:

1. The loss of dissolved gas may have caused, through shrinkage of the reservoir oil, a decrease in the oil saturation in the formation. Lower saturation decreases the permeability to oil.

2. The loss of dissolved gas may also have caused an increase in the viscosity of the remaining oil. A higher viscosity makes the displacement of the oil more difficult.

3. The amount of gas remaining in the reservoir may be insufficient to supply the needs for gas injection, and may even be inadequate for fuel for the secondary-recovery operations.

4. The mechanical condition of the wells may be poor, and high costs may be incurred for reconditioning them. The wells may even have been so damaged that they cannot be used for either production or injection, and new wells may have to be drilled for secondary-recovery operations.

5. Improperly abandoned wells may have permitted water from the surface or from water-bearing formations to enter the oil-bearing formation in such manner as to trap or block the remaining oil.

6. Irregular encroachment of water from an improperly controlled natural water drive may have left most of the remaining oil trapped under such conditions that it cannot now be recovered.

7. Dissipation of a gas cap during the primary recovery operation may have allowed much of the reservoir oil to enter the formations formerly filled with gas.

It is evident from all of these considerations that secondary recovery will be feasible in only a limited number of old pools. There are many situations in which it is reasonably obvious that secondary recovery would not be practical. In any pool already depleted by an efficient primary method the residual oil is largely unrecoverable by conventional displacement methods. In any pool depleted by a natural water drive, whether the water influx has been properly controlled or not, the residual oil will usually be either at so low a saturation or so trapped and blocked by water as to be substantially unrecoverable by a process that depends on injection of gas or water. A pool in which there has been a substantial recovery of oil by gravity drainage after depletion by dissolved-gas drive may have a low residual oil saturation in spite of the prior operation under a dissolved-gas drive. In addition to those pools that must, for the most part, be excluded from consideration because of the nature of the primary recovery method, there must be excluded those pools that have been damaged excessively through various causes.

There are also positive requirements for effective recovery of oil by a gas-injection or a water-injection operation, whether the injection be undertaken during the primary recovery stage or later. There must be sufficient continuity and uniformity of the producing formations to permit effective displacement of the oil from all of the formation. Great variations of formation permeability are not conducive to effective displacement. Streaks of high permeability, fractures, and fissures may cause difficulty by allowing the injected gas or water to flow primarily through the more permeable channels without flushing the oil from the remainder of the formation. There must be an absence of extreme lenticularity in the producing formations. The viscosity of the residual oil must be low enough to permit it to be displaced without the employment of excessive volumes of gas or water. The permeability of the formation must be sufficient to permit both injection and production at reasonable rates. Above all, the amount of oil recoverable by injection of gas or water must be sufficient to support the secondary-recovery operation.

When all of these many factors are taken into account it appears that possibilities for the recovery of additional oil by secondary operations following primary depletion are most attractive in pools of shallow to moderate depth, that have been depleted by dissolved-gas drive, that had no original gas cap, that had wells of reasonably high initial productivity, and that contained a reasonably large original quantity of oil per unit area in a single, continuous formation. Preliminary selection of such pools may be made largely on the basis of records of past production and existing drillers' logs. Final selection, and inauguration of a secondary-recovery project should be based on further factual information and thorough technical study. Many attempts at secondary recovery have been unsuccessful because of inadequate information and failure to make a thorough analysis. In almost all cases it is necessary in older pools to obtain through the drilling, coring, and logging of new wells the basic facts concerning the physical characteristics of the reservoir and its residual oil saturation that are required to determine the feasibility of secondary recovery and to plan the operation.

Secondary-recovery operations have, to date, been confined primarily to sandstone reservoirs at shallow depth. They have been employed extensively for many years in the older producing areas of the East, particularly in the Bradford area of Pennsylvania and New York, and more recently in certain producing formations in Oklahoma, eastern Kansas, Illinois, and north-central Texas. In most of the older shallow pools of these areas rather close spacing of wells was employed for the primary recovery, and secondary-recovery operations have been greatly influenced by the local conditions and by the former production practices.

In some cases, because of the poor mechanical condition of the old wells, it has been necessary to drill all new wells for the secondary operations. Often it has been necessary to re-work the old wells to assure their being properly plugged so that they will not permit escape of fluids from the producing formation into other zones. In many cases it has been possible to recondition the old wells and to use them for the secondary operation. In any event, there is a substantial development expense associated with secondary recovery, for adequate geologic and engineering information must be obtained, wells must be provided, a supply of water or gas for injection must be secured, and facilities must be provided for carrying on the injection and production operations over the life of the project.

In secondary-recovery operations, even more than in primary operations, the ultimate recovery obtainable is quite dependent on the economics. Investments in wells and other facilities must be carefully controlled in relation to the expected recovery to be obtained. If efficient ultimate recovery is to be obtained the operations must be so designed as to permit their continuation until the reservoir is substantially exhausted of its recoverable oil content before the economic limit is reached. The thoroughness with which a reservoir is depleted of its recoverable oil content depends, as in primary recovery employing water drive or gas drive, on the completeness with which the entire reservoir is flushed with water or gas, and on the final oil saturation in the flushed portion of the reservoir. Whether water drive or gas drive be employed to bring about the secondary recovery, it has been found in practice that relatively large volumes of the displacing fluid must be produced along with the oil to attain a high ultimate recovery.

WATER FLOODING

Secondary recovery by water flooding has been carried on most intensively in the Bradford field, and many of the practices employed in other areas have developed from the experiences at Bradford.

It is the usual practice to employ geometric well patterns with producing wells and injection wells in alternating arrays. The pattern most commonly employed is the "five-spot," which consists of injection wells at the corners of a square and a producing well at the center. Repetition of the pattern provides parallel alternating rows of staggered injection and producing wells. Figure 11 is a diagram of the water-flooding process. In the shallow pools in which most secondary water-flooding operations have been carried on, the distance from injection wells to producing wells is often in the range of 200 to 400 feet for "five-spot" patterns. This spacing of wells is much closer than that now normally employed in the development of new pools for primary recovery.

The distance between wells in a secondary-recovery operation is determined largely by economic factors. The maximum number of wells such an operation can support is determined by the ultimate recovery to be expected, by the price of the oil, and by the cost of the wells. The cost of a well depends primarily on its depth. The minimum number of wells suitable for a particular operation depends to a large extent on the physical characteristics of the producing formation and on the economic effects of a delay in obtaining a return. The less permeable a formation, and the greater the distance between injection and producing wells, the greater is the time required to flush a pool with water.

The mechanism of displacement of oil by water is no different in secondary-recovery operations than in primary water drive. The same types of control must be exercised to assure efficient flushing of the reservoir. The employment of injection wells localizes the area of access of the water and imposes a geometric limitation that is not encountered in a natural water drive. However, this handicap is offset, in part, by the positive control over the rate at which water is supplied to the producing formation, and by the fact that it is possible to control to some degree the relative rates of injection into strata or layers of different permeability.

In most secondary water-flooding operations the injected water displaces oil from the vicinity of the injection wells before the effects of the water injection are noticeable at the producing wells. The displaced oil, in turn, displaces gas from the pore space and locally increases the oil saturation. In this manner, there usually develops ahead of the advancing water a zone of high oil saturation that moves toward the producing wells. Until this "bank" of oil reaches the producing wells the injection of water has substantially no effect on the production. Thus, there is nearly always a delay in obtaining any return from a secondary water-flooding operation. The duration of the delay depends on the rate of water injection, the residual oil saturation in the sand, and the distance between the injection and producing wells.

When the zone of high oil saturation reaches the producing wells the permeability of the formation to oil is locally increased, and

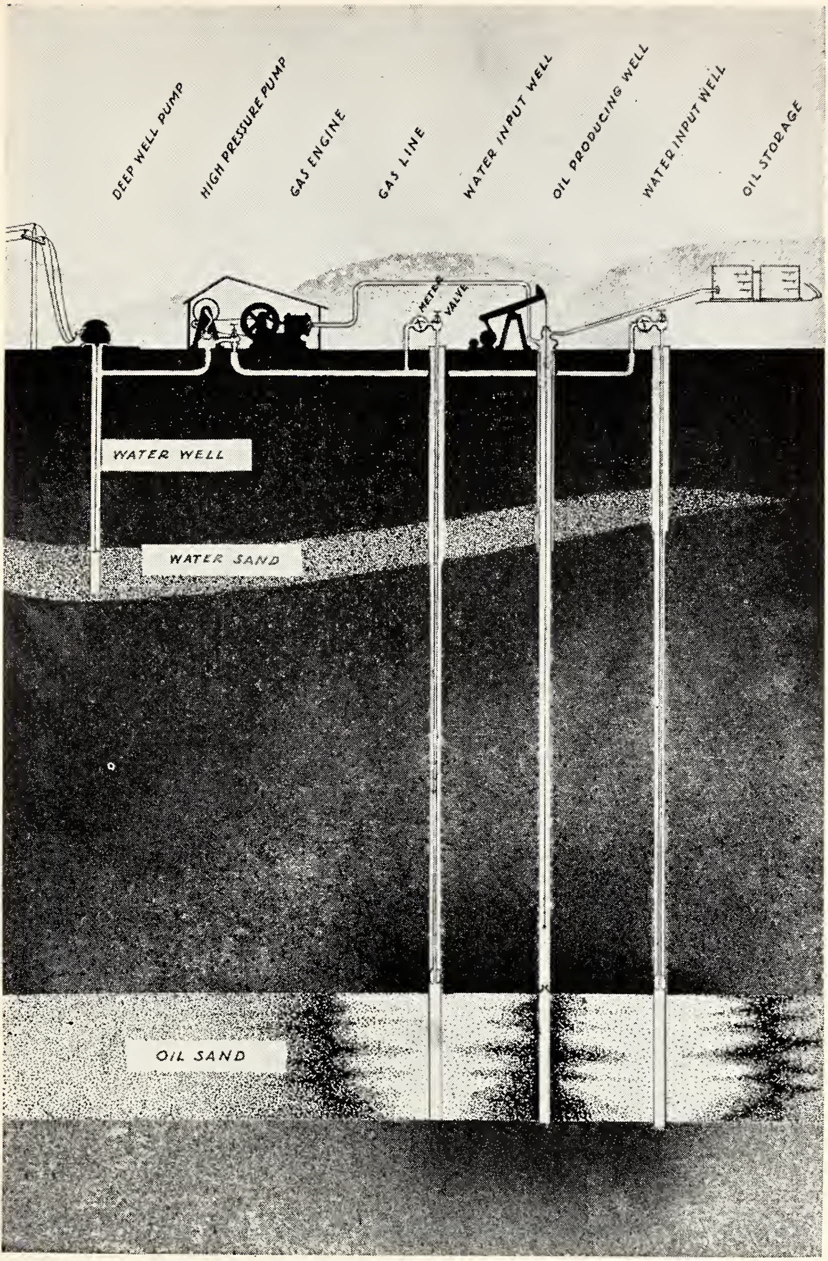

Fig. 11—Water-Flood Process

usually the pressure is also increased. If the producing wells are kept on production during the period of development of the flood, the arrival of the oil bank is usually indicated by a substantial increase in the rate of production. When a secondary-recovery operation is carried on with newly drilled production wells it is common practice to delay their production until sufficient water has been injected to develop a high oil saturation in their vicinity. In either event, a substantial amount of oil production relatively free of water is often obtained.

Production of water usually begins when the most permeable strata have been flushed. Thereafter, the rate of production of oil declines and the rate of production of water continuously increases. The operation ceases when the rate of production of oil has declined to too low a level to support continued operation.

A zone of high oil saturation does not always develop ahead of the advancing water, and in some operations production of water takes place from the start. Whether or not an oil bank develops depends largely on the relative-permeability characteristics of the producing formation, on the saturations of water and oil at the time the water injection is started, and on the viscosity of the oil. If the conditions at the start of the flood are such that oil can move more readily than water can move, water selectively accumulates and the oil moves ahead to develop an oil bank. If the conditions are such that water can move through the formation more readily than oil, no bank develops. Which behavior to expect can usually be determined from adequate data on the producing formation and its fluid content prior to inauguration of a water-flooding operation. Some attempted water-flooding operations have been failures because a bank of oil did not develop and oil was never produced at sufficient rate to justify the operation.

GAS INJECTION

The injection of gas into a reservoir for the purpose of increasing the recovery of oil has been more widely practiced than the injection of water. The resultant increases in ultimate recovery have been far less spectacular than some of the increases obtained through water injection, because gas is inherently a less efficient driving medium. However, injection of gas can sometimes be initiated at a much lower development cost than water flooding, and some increase in oil recovery is usually obtained even with the injection of relatively small amounts of gas. The injection of gas into a reservoir can be started when a pool is relatively new, or at any stage thereafter.

The term "repressuring" has often been used to describe the operation wherein gas is injected into a producing formation. Although local increases of reservoir pressure occur in the vicinity of the injection wells, no over-all restoration of pressure to any substantial degree is usually involved, and, strictly speaking, the term "repressuring" is a misnomer as applied to most gas-injection operations.

The lower efficiency of gas as compared with water as a displacement agent in secondary-recovery operations is due to the same fundamental causes that make gas alone an inefficient agent in primary recovery. These are the very low viscosity of gas and the fact that it is a "non-wetting" fluid and is thus incapable of selectively entering and ejecting oil from the smaller voids in the rock. Because of its low viscosity, injected gas very seldom produces ahead of the drive the "bank" of oil that is characteristic of secondary water drive. Gas is much more mobile than water and travels rapidly throughout the reservoir. Thus, injected gas may affect not only those wells adjacent to the injection wells, but other producing wells also. Wells some distance away from the injection well are sometimes affected relatively soon after the start of injection.

The injection of gas in one area locally increases the reservoir pressure and causes a migration of both gas and oil in a direction away from the injection well. Under some circumstances the injection of gas by one operator may result in an increase in the ultimate recovery by his neighbors, and little improvement, or possibly even a loss, in his own recovery. Although there are a few pools in which one operator controls all or most of the acreage and has conducted highly successful gas-injection projects, the divided ownership that exists in most pools usually makes it impractical for a single operator to inject gas without cooperation from the others. In some pools, simultaneous and cooperative injection of gas by a majority of the operators is practiced. The most practical and most equitable arrangement, however, is usually that in which there is unit operation of the pool, with each operator paying his share of the cost and receiving his proportionate share of the increased recovery. Such an operation permits proper location of injection and producing wells with reference to the configuration of the reservoir, without the artificial restrictions imposed by lease boundaries, and provides means for scientific control of the injection in such manner as to yield the maximum over-all increase in recovery. There are many examples of successful gas-injection projects on a fully cooperative or unit-operation basis. As the advantages of unit operation are becoming better known more and more pools are being operated as units.

In the event injection of gas is inaugurated in a pool prior to substantial exhaustion of the original gas content, the gas used for injection is usually that produced with the oil in excess of lease fuel requirements. However, in many pools secondary recovery is not resorted to until the reservoir pressure has been dissipated and the original supply of gas has been exhausted. Under such circumstances gas must be obtained from other sources. In such instances some operators have used air instead of natural gas. Mechanically, air is probably just as effective as natural gas. However, it has serious disadvantages. The gas produced at the oil wells is diluted with air, and serious accidents have resulted from the formation of explosive air-gas mixtures. The air has a very severe corrosive effect on the producing wells and may cause oxidation of the oil and difficulties due to emulsification of the oil with water.

The gas-injection wells are sometimes drilled especially for the purpose, but are often converted producing wells. Geometrical patterns of injection and production wells are used much less in gas-drive than in water-flooding operations. However, there is some evidence that geometrical patterns and intensive drives are also necessary in some pools for attainment of efficient ultimate recovery by gas drive.

The gas-oil ratios of the wells in a semi-depleted pool often provide an index to the results that might be anticipated from injection of gas. Low ratios are usually indicative of a reasonably low saturation of gas, from which it may be inferred that the injected gas will displace a substantial quantity of oil before the reservoir gas saturation rises sufficiently to lead to prohibitive production of gas. On the other hand, high gas-oil ratios prior to the start of gas injection indicate that the reservoir has a high gas saturation, or a high permeability to gas, and that the produced gas-oil ratio will rise quickly after the start of gas injection.

In any event, it is characteristic of gas-drive operations that the gas-oil ratio continuously rises as the oil saturation of the reservoir is reduced. Unless the rate of gas injection is progressively increased, the rate of production of oil declines. Such operations reach their economic limit and are terminated when the gas-oil ratio rises to such a level that continued injection of gas in the required quantity can no longer be sustained by the declining oil production.

If a pool contains a high oil saturation and a low water saturation substantially higher ultimate recoveries of oil can usually be obtained by water drive than by gas drive. However, some pools contain, for one reason or another, relatively high water saturation. When such a situation exists gas drive may be more effective than water drive in obtaining additional recovery of oil.

LIMITATIONS OF SECONDARY RECOVERY

It is readily apparent that although secondary recovery may be quite effective in obtaining additional oil from certain depleted fields, a two-stage operation comprising an inefficient primary operation followed by a secondary operation must be considered a poor substitute for a single recovery method that employs efficient procedures from the beginning. A two-stage operation is both more costly and less efficient. Not only are many reservoirs so damaged by an inefficient primary-recovery method that they are rendered unsuitable for secondary recovery, but in many the available quantity of recoverable oil is not sufficient to support two complete operations.

From the economic standpoint, both the total development expense and the total operating expense can be kept at a minimum if the recovery operation is so designed and so carried out as to attain a high degree of recovery in a single operation. The savings effected through not having to re-drill or re-work the wells can be used to advantage to supply facilities for the additional injection of gas or water where such is required. Substantial savings in the total operating expenses result from reduction of the total period of time during which the operations are carried on.

Since the economic factors control to a large extent the final amount of oil recovered, the economies made possible by a single, efficient operation often contribute materially to the attainment of more efficient ultimate recovery. Furthermore, the physical changes that take place in a reservoir as a result of an inefficient primary-recovery method often reduce the recoverability of the remaining oil. When all of the factors are taken into account the aggregate effects are such that efficient primary-recovery methods, including the injection of gas or water as a part of the primary operation when such injection is required, can be expected to yield substantially greater ultimate recoveries from the reserves now existing in undepleted fields than could be anticipated if these fields were to be depleted by inefficient methods followed by secondary-recovery operations.

OIL RESERVES RECOVERABLE BY SECONDARY METHODS

It is practically impossible to estimate the total quantity of oil in the United States that is economically recoverable by secondary methods from fields already depleted, now in the stripper stages of recovery, or now undergoing primary operations with inefficient methods. The reasons are several. In the first place, no comprehensive information is available with respect to the total amount of oil still remaining in the depleted reservoirs, or which will remain after exhaustion of those pools that are now producing. In the second place, the amount of such oil that might be economically recoverable by known secondary-recovery methods is highly uncertain because of the small margin between the costs of recovery and the value of the oil recovered. For any given recovery method, development pattern, and price of oil, a minimum quantity of recoverable oil must be anticipated before development can proceed. If the style of development remains the same, the amount of oil potentially recoverable by secondary methods will vary with the price and with the depth and thickness of the producing formation.

Undoubtedly, there still remains in the ground a tremendous quantity of oil in depleted or near-depleted fields. From time to time estimates of the possible total quantity of such oil have been made by taking the cumulative discoveries of oil and applying a factor presumed to represent the amount of oil left behind for each barrel produced or expected to be produced by primary methods. Such estimates lead to figures in the range of 50 to 100 billion barrels of unrecovered oil. Of course, a large fraction of such oil is not physically recoverable by any process known today; furthermore, much of it is in fields unsuited to known secondary-recovery methods. The great bulk of it could not be recovered by known methods at costs even greatly in excess of present production costs. When consideration is given to the feasibility of synthesizing hydrocarbon fuels and lubricants from shale oil and coal at costs not too greatly exceeding the costs from crude oil, it is apparent that such synthetic processes will set a ceiling that crude oil prices can never exceed. This availability of auxiliary sources of supply for the products now manufactured from crude oil will make it impractical to recover by known secondary methods more than a small fraction of the known unrecovered oil in depleted or near-depleted pools.

In spite of the severe limitations on the probable amount of oil to be recovered by future secondary operations, the knowledge that tremendous quantities of unrecovered oil remain underground in known locations has served as a great stimulus to research directed toward improvement of known recovery processes and toward the discovery and development of new methods of recovery. Such research has been carried on not only by the industry, but by state agencies and the United States Bureau of Mines as well. The accelerated interest shown recently in such research is a healthy trend. Out of it may come not only improved techniques of secondary recovery but methods leading to improved primary recovery as well.

REFERENCE LITERATURE

The reader who is especially interested in secondary recovery will find the details thoroughly covered in the literature. *Secondary Recovery of Oil in the United States* (Second Edition, published by the American Petroleum Institute in 1950, contains not only technical papers covering nearly every phase of secondary-recovery operations, but a supplementary bibliography that lists over two thousand pertinent references.

Chapter VIII

PRESSURE MAINTENANCE

Part One . . . OIL RESERVOIRS

It has been explained in preceding chapters that excessive decline of reservoir pressure is almost always a direct indication of inefficient oil recovery. Excessive decline in pressure often shows that dissolved-gas drive, by far the least efficient recovery method, dominates the reservoir. As a result, there has developed a tendency to consider pressure maintenance somewhat nebulously as synonymous with efficient recovery and, even more specifically, to indicate use of water drive or gas drive, either natural or artificial, in lieu of dissolved-gas drive, regardless of whether or not reservoir pressure is actually maintained.

There are many considerations other than reservoir pressure that influence recovery efficiency. Employment of a migratory displacement process is a basic essential. In order to avoid confusion, therefore, a distinction must be drawn, if possible, between pressure maintenance as an *index* of efficiency, and the degree to which maintenance of reservoir pressure is a necessary condition for efficient displacement by a suitable process.

For example, it has already been shown that gas drive and water drive have certain advantages over dissolved-gas drive. Their advantage is demonstrated by their employment in secondary-recovery operations to obtain additional oil from pools already depleted by dissolved-gas drive. The success of secondary recovery also specifically shows gas drive and water drive to be effective at reduced reservoir pressure. The degree to which still further advantage might be gained by their use to effect the primary recovery, and the specific degree to which their effectiveness might be increased by maintenance of reservoir pressure during the displacement require analysis.

Pertinent questions that arise immediately are:

1. What is the maximum reduction of pressure that can be allowed to prevail in a particular reservoir without damage to the ultimate recovery?
2. Can the pressure be maintained adequately by the natural

response of the reservoir to proper controls, including, particularly, control of the production rate?

3. Is injection of gas or water or both required to remedy deficiencies?

In order to answer these questions it will be helpful to recognize that individual reservoirs differ widely from one another in their characteristics. Some reservoirs are capable of maintaining their own pressure to a high degree under controlled operating conditions; others, for any one of many reasons, cannot do so.

A reservoir may maintain its own pressure if its physical environment is such as to permit the influx of sufficient water through the producing formation at small or moderate pressure gradient, or if it initially contains a quantity of free gas adequate to fill the oil zone at moderately reduced pressure. The necessary conditions are found in many oil pools throughout the world in both sands and carbonate rocks. Examples are many of the Miocene sand pools of Louisiana, and Frio sand pools of Texas.

Reservoirs not capable of maintaining their own pressures are those deficient in free gas and whose physical characteristics or surroundings are such that influx of water at moderate pressure gradient is inadequate to replace the produced oil at a reasonable rate. Examples of this type are found among some of the oil accumulations in the Permian formations of West Texas, and in lenticular sand pools in many areas. The pressure in a reservoir of this type can be maintained only by injection of gas or water.

The specific effects of pressure maintenance, as well as the procedures required to obtain pressure maintenance, differ not only from pool to pool but are not the same for water drive and gas drive. Separate consideration of each recovery process is therefore required.

WATER-DRIVE RESERVOIRS

Maintenance of Pressure by Natural Water Drive

Necessary Conditions

Maintenance of reservoir pressure by natural water drive can be obtained through regulation of the production rate if the physical nature of the reservoir and its surroundings are such that water can feed into the oil-bearing portion of the formation at a small or moderate pressure differential in sufficient volume to displace the oil at a reasonable rate.

As was shown in Chapter III, oil accumulations are found in various types of porous rocks, including, particularly, sandstones, limestones, and dolomites. The type of formation in which the oil occurs is pertinent primarily insofar as it may affect the chances of having continuous porosity and permeability over a large area outside the oil accumulation. The thickness and lateral extent of the formation, the magnitude of its porosity and permeability, and the size and shape of the oil reservoir all have a direct bearing on the degree to which pressure can be maintained by natural water drive. Those reservoirs in which the producing formation extends laterally with appreciable thickness and moderate to high permeability are capable of receiving large quantities of water with small pressure differential. Reservoirs in which the formation becomes discontinuous because of disappearance of porosity or from faulting, or that have too low permeability and thickness are usually incapable of having natural water drive.

Mechanism of Pressure Maintenance

It is apparent from elementary considerations that a reservoir cannot be maintained at its original pressure by natural water drive, because pressure is consumed by friction when water flows through a formation. In some cavernous formations the decline in pressure has been so small as to be almost undetectable, but in the usual water-drive pool a pressure decline of from one hundred to several hundred pounds a square inch is experienced.

The specific degree of pressure maintenance, or, conversely, the reservoir pressure decline that prevails in a water-drive pool, is a function of the rate of net volumetric withdrawals from the reservoir. This fact is readily apparent from analysis of the process taking place when water enters a reservoir. It has been shown in prior chapters that when fluids are withdrawn from a reservoir the pressure must decline so that the fluids remaining in the reservoir can expand and fill the vacated pore space. The reduction of reservoir pressure creates a difference in pressure between the oil zone and the water-filled portion of the formation, which was originally at the same pressure as the oil reservoir. This pressure difference causes water to flow into the oil zone; the rate of influx of water will of necessity be such that the entire pressure difference will be consumed as friction in the water-bearing part of the formation. As will be shown later, the water that enters a reservoir must flow from progressively greater distances, and the friction consumed in the water-bearing portion of the formation is dependent not only on the rate of movement of the water but also on the physical charcteristics of the formation and the distance through which the water must move. For these reasons, a direct and constant proportionality does not suffice to relate the rate of water influx to the pressure decline of the oil zone. Nevertheless, it will facilitate understanding of the mechanism of maintenance of pressure by water drive to defer consideration of the complicating factors and to analyze the process of stabilization of pressure *as if* the rate of influx of water were directly proportional to the difference between the original pressure in the water zone and the prevailing pressure in the oil zone. This approach is not hypothetical or unrealistic but represents a reasonable approximation of the actual situation in many pools, particularly those in formations of high permeability. The effect of the other factors is to cause the rate of water influx for a fixed pressure difference to decline gradually as production continues.

The invading water cannot maintain the pressure in the oil zone until it can enter the reservoir at a sufficient rate to fill continuously the space being voided by the production of oil and can thus stop replacement of the oil by expansion of those fluids already present in the reservoir. The reservoir pressure continues to decline as a result of oil production until the resulting differential brings water in fast enough to provide the required replacement. The reservoir pressure can then stabilize.

These facts may be visualized readily through a simple numerical example. Let us consider a small reservoir in a formation of such characteristics that a pressure differential of 100 pounds per square inch between the oil zone and the water zone will cause water to flow into the oil zone at a rate of 100 barrels a day. If the pool is produced at a rate of 500 barrels a day of reservoir oil the pressure within the oil zone will begin to decline and water will begin to enter the reservoir. The pressure differential will at first be small, and the resulting water influx will be very small, so that most of the produced oil will be replaced within the reservoir by expansion of the reservoir fluids and not by the invading water. As the reservoir pressure continues to decline, the increasing pressure differential will cause water to enter the oil zone at a greater and greater rate. When the differential has reached 100 pounds per square inch the invading water will be replacing one-fifth of the oil being produced. This process will continue until the pressure differential gets to be 500 pounds per square inch, at which time the rate of influx of water will have become 500 barrels a day, which is sufficient to replace all of the oil being withdrawn, without further expansion of reservoir fluids. Thus, the reservoir pressure must decline continuously until the pressure differential grows large enough to bring about a balance between the rate of influx of water and the rate of reservoir withdrawals.

If, in the example under consideration, the rate of production of oil had been 1,000 barrels of reservoir oil a day, a balance would not have been reached until the reservoir pressure had declined 1,000 pounds per square inch. Conversely, if the rate had been only 250 barrels a day the reservoir pressure would have become stabilized at a value only 250 pounds per square inch lower than the original.

It is readily apparent that if the reservoir under consideration were 2,200 feet deep and had an original pressure of 1,000 pounds per square inch, stabilization of reservoir pressure could never take place if the rate of withdrawal continuously exceeded 1,000 barrels a day, for the water influx could never become sufficient to replace the withdrawals. Operation at such a high production rate might lead to the condition known as delayed water drive. Water influx would not have any significant effect during most of the life of the pool, and the oil recovery would be dominated by other processes. Eventually, the reservoir pressure would become so low that the wells could not continue to produce at a high rate, and many might be abandoned. Since the rate of influx of water is fixed not by the rate of withdrawal of oil but by the pressure differential caused by the oil production, water would continue to enter the reservoir at a rate increasing toward 1,000 barrels a day. When the oil withdrawal rate finally declined to a low value this water influx might become noticeable. If the water were not produced, the invading water might eventually flush the entire reservoir at low pressure.

The facts outlined may be summarized as follows:

1. The rate of influx of water into a reservoir is proportional to the difference between the original reservoir pressure and that prevailing at any time, or to the total decline of reservoir pressure from the beginning of production.

2. The reservoir pressure in a water-drive pool declines continuously until a balance is reached between the rate of influx of water and the rate of net volumetric withdrawals from the reservoir.

3. Until such time as a balance is reached between the rate of

influx of water and the rate of withdrawal the invading water acts to decrease the rate of decline of reservoir pressure to the extent that the water occupies a part of the reservoir volume, but it does not sustain or maintain the reservoir pressure.

4. The reservoir pressure stabilizes when the pressure decline becomes large enough to bring about a balance between the rate of influx of water and the rate of withdrawal of fluids from the reservoir.

5. The level at which the reservoir pressure becomes stabilized is dependent on the physical characteristics of the formation, but for any reservoir it may be fixed at will by regulation of the withdrawal rate.

6. When the reservoir pressure is stabilized and is maintained by water drive all reservoir withdrawals are replaced by an equivalent volume of invading water, and no oil is recovered by any mechanism other than displacement by water.

7. Stabilization of pressure can never take place if the rate of withdrawal from the reservoir continuously exceeds the rate at which water can enter.

Quantitative Determination of Degree of Pressure Maintenance

The basic question of the degree to which the reservoir pressure can be maintained by natural water drive in any specific case resolves itself into a quantitative determination of the rate at which water will enter the pool in response to a pressure decline. Correspondingly, an answer to the question of the rate at which the reservoir pressure will decline requires a quantitative determination of the effects on pressure within the reservoir caused by withdrawals and by water influx.

As was explained in Chapter VI, the response of the pressure within the reservoir to the total net volumetric withdrawals can be calculated by the volumetric balance method. From records of reservoir pressure and of withdrawals of oil, gas, and water during the past production, the volumetric balance may be used to calculate the cumulative volumes of water that have entered a reservoir over successive time intervals. Such calculations provide directly from the actual past performance of the reservoir an observed relation between the prevailing reservoir pressure, the water influx, and the elapsed time. By similar calculations the reservoir pressure at any time in the future may be predicted for any assumed total withdrawal of reservoir fluids, provided the total volume of water that will have invaded the reservoir within any future time be known.

Volumetric balance calculations based on the past performance of a reservoir invariably show that the rate of influx of water for a unit of pressure differential is not constant but decreases continuously with elapsed time. This complicates the forecasting of the rate at which the reservoir pressure will decline and the time and pressure level at which stabilization of the pressure will occur. It also indicates that the reservoir pressure will never remain stabilized at a constant value at a constant rate of withdrawal of reservoir fluids but will continue to decline unless the withdrawal rate is continuously decreased after stabilization is attained.

Calculation of Rate of Water Influx—In order that quantitative forecasts of reservoir pressure might be made, the mechanism of the flow of water into a reservoir has been analyzed mathematically, and quantitative relationships have been derived between the various interrelated factors. Figures 12 and 13 show results of such calculations for the influx of water into a circular reservoir through a formation of constant thickness. Figure 12 is a plot of the reservoir pressure decline required to bring about a constant rate of influx of water, and Figure 13 is a plot of the cumulative water influx resulting from a constant reservoir pressure decline.

The complexities of the mathematics are so great that equations relating the rate of influx of water to the pressure differential and to the elapsed time have been derived only for certain simplified situations where the thickness, the porosity, and the permeability of the water-bearing formation are assumed to be uniform. In spite of these limitations, when the equations are fitted to the actual water influx calculated from field records by the volumetric balance they often yield remarkably accurate results and may be used to predict for a number of years into the future the relation between water influx and reservoir pressure. Such calculations are often completely satisfactory for the planning and control of operations.

An alternative method employed to determine and forecast the water influx into a reservoir is the use of electrical devices that in effect solve both the volumetric balance and the water-influx equations. These electric reservoir analyzers have two advantages over the usual calculation procedures. The less important advantage is their ability to perform an analysis quickly; the more important is that it is possible to take into account with these analyzers some of the known physical irregularities of the formation and thus to obtain

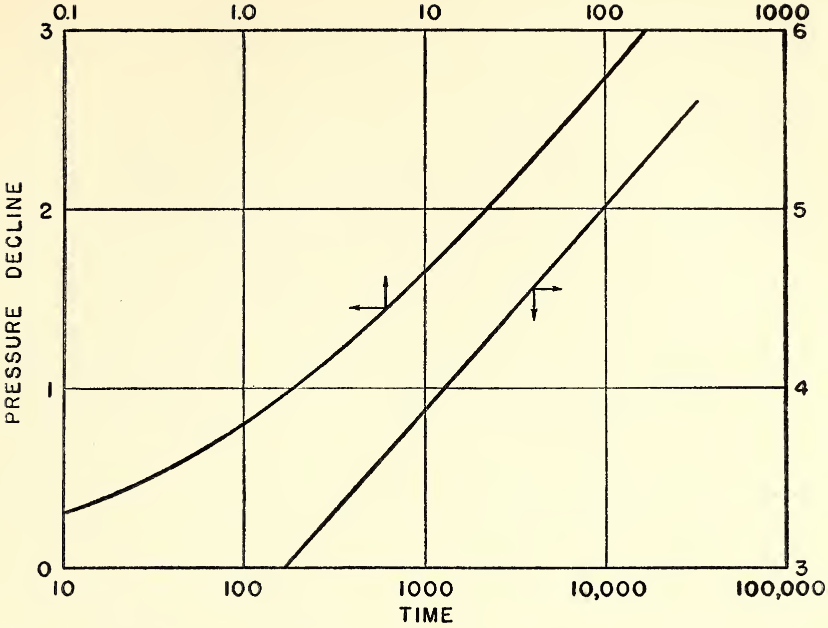

FIG. 12—Reservoir Pressure Decline for Constant Rate of Water Influx

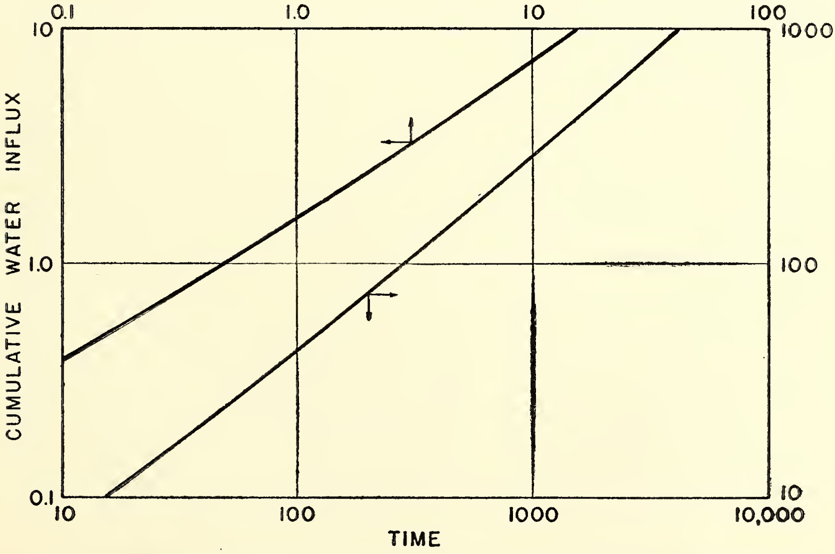

FIG. 13—Cumulative Water Influx for Constant Pressure Difference

more accurate forecasts than are usually possible by the purely mathematical approach.

Mechanism of Water Flow

These mathematical developments are particularly helpful in providing a direct insight into the mechanism of the movement of water and the individual physical factors that affect it. They show specifically the reason for the observed decrease in the rate of influx of water for a unit of pressure differential. The reason for this decrease is that as production continues and water flows into a reservoir, the water immediately adjacent to the oil zone is replaced by water a little further removed, which in turn is replaced by water from still further away. As time goes on, water must flow from a progressively greater distance and encounters progressively greater frictional resistance; as a result, the flow either slows down or a greater pressure differential is required to sustain the rate.

The void space in the water-bearing portion of the formation does not become emptied of water but remains filled with water under pressure; therefore, the water that invades the reservoir must come entirely from expansion of the water in the surrounding formation. Thus, reduction of the pressure in the surrounding formation is required to yield the water. This reduction in pressure starts at the edge of the reservoir and, as time goes on, must spread out laterally to greater and greater distances to make available the required volume of water.

The rate at which water can flow in response to a unit pressure differential at any position in the formation is directly proportional to the formation permeability. The amount of water that a unit volume of formation can yield for a given pressure reduction is proportional to the amount of water it contains and to the compressibility of its contained water. Thus, the initial rate at which water can flow into a reservoir in response to a unit pressure differential is fixed by the size of the reservoir and the thickness and permeability of the formation. The rate, however, at which the reduction of pressure can be propagated through the formation is dependent not only on the permeability but also on the volume of contained water and on its compressibility. The ultimate amount of water that a particular formation is capable of yielding is dependent on how much water it can yield by expansion when the entire aquifer has its pressure reduced.

Need for a Large Aquifer

The compressibility of water is very slight, only about three parts in a million for a pressure reduction of one pound per square inch. If natural water drive is to be used to replace at a moderate reduction of reservoir pressure all of the oil produced from a reservoir, a tremendous volume of tributary water must be available. For example, if 100 million barrels of water is required over the life of a pool to replace the produced oil at a reservoir pressure reduction not to exceed 500 pounds per square inch, the amount of water that would have to expand would be over 60 billion barrels. This amount of water would fill all of the pore space in a formation 50 feet thick having 20% porosity over an area of 775,000 acres or 1,200 square miles.

It is apparent from these considerations that a large contributory aquifer with sufficient permeability to allow pressure reduction to take place over a great area is an essential for pressure maintenance by natural water drive.

It has been found from analysis of the pressure behavior of water-drive pools as well as the behavior of artesian aquifers supplying water wells that the amount of water apparently yielded by a formation for a unit of pressure decline is frequently greater by a factor of two to ten times than would be anticipated from the known compressibility of pure water. The source of this excess yield has not been identified; it may reflect vertical movement of water from other formations into the permeable formation carrying the water, or compaction of the formation, or it may reflect inability of the mathematical calculations to take into account certain physical variations of the formation. In any event, the uncertainties regarding the specific water yield of a formation are sufficiently great that quantitative forecasting requires a tie-in with the observed history of reservoir withdrawals and pressure through volumetric balance calculations.

It is evident from analysis of the mechanism of the influx of water into a reservoir that the rate of water influx for a unit of pressure gradient is governed by the characteristics of the formation outside of and even remote from the reservoir rather than by the formation characteristics within the reservoir. For example, high formation permeability within a reservoir might facilitate equalization of pressure and uniformity of flushing if water were available, but high permeability inside a reservoir cannot deliver water to the reservoir. Determination of the regional geologic conditions, including the thickness, porosity, and permeability of formations at some distance away from oil reservoirs, is important in dealing with natural water drive. Dry exploratory wells drilled in most producing areas usually provide sufficient access to the water-bearing formations of interest to permit determination of the thickness and, to some extent, the degree of physical continuity, but seldom are determinations of porosity and permeability made on complete cores from a formation known to contain no oil or gas.

Pressure Interference Between Pools

The rate of propagation of the pressure decline outward from the edge of a reservoir through the water-bearing formation is such that the pressure may be significantly reduced many miles away from an oil reservoir. Thus, if there are two or more water-drive pools producing from the same formation in the same general area they all draw their water from the same source, and each adversely affects the availability of water to the others. This effect is noticeable as a pressure interference between pools.

A very pronounced example of pressure interference is found in the Woodbine formation in eastern Texas. There, a dozen or more pools, including several of major size, draw on the Woodbine formation for water drive. The pressure in the water-bearing portion of the formation has been significantly reduced over an area of several thousand square miles. This reduction of pressure has been such that when the Hawkins pool was discovered in 1940 the pressure in one part of the reservoir had already been reduced 280 pounds per square inch below its initial value as a result of prior production from other Woodbine sand pools, including, in particular, the East Texas field, some 20 miles to the east of Hawkins.*

MAINTENANCE OF PRESSURE BY WATER INJECTION

The maintenance of pressure in a reservoir by artificial water drive involves much less difficult considerations than maintenance of pressure by natural water drive. The degree of maintenance is dependent solely on the amount of water injected relative to the reservoir withdrawals. If the volume of injected water is equal to the volume of withdrawals the reservoir pressure may be maintained at its original value; if injection lags, the reservoir pressure will decline. The specific degree of reservoir pressure decline can be calculated directly from a volumetric balance.

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*Bell, J. S., and Shepherd, J. M., "Pressure Behavior in the Woodbine Sand," *Journal of Petroleum Technology,* Jan. 1951.

Pressure maintenance by water injection is normally considered in relation to closed reservoirs having no access to an aquifer capable of supporting natural water drive. There is a growing tendency, however, to use water injection to dispose of produced water by returning it to the producing formation at the edge of a reservoir to sustain a natural water drive, to inject water to supplement an inadequate water drive, and to create a water drive in a formation that is continuous but has too low a permeability to provide natural water drive to any appreciable extent.

Whenever water is injected at high pressure around the edges of a pool from which the formation extends laterally outward with continuous permeability a part of the injected water may flow outward into the aquifer instead of into the oil zone. If such outward flow occurs it must be taken into account in calculating the balance between reservoir withdrawals and water injection. Even when the pressure gradient around a pool is such that the injected water cannot literally flow outward, the local change in pressure gradient resulting from the injection reduces any natural influx of water by an amount equivalent to the indicated outward flow. The effects of natural water drive and water injection on each other, and their net combined effect on the maintenance of reservoir pressure can be determined by the methods used for natural water drive.

The permeability and size of a reservoir affect the response of its pressure to water injection. If water is injected only around the edges and oil is taken out over the entire pool, the fluid movements within the reservoir will create a pressure gradient across the pool. The reservoir pressure will be highest adjacent to the injection wells and lowest in the center, or in the position most remote from the injection wells. If a pool is very large and has low permeability this pressure differential may be so great that some areas of the reservoir may have low pressure in spite of the water injection. This situation is not encountered when water is injected through wells interspersed among the producing wells throughout the pool.

Effects of Pressure Maintenance on Oil Recovery

With Natural Water Drive

In consideration of the effects of pressure maintenance on recovery efficiency in a reservoir produced by natural water drive it is not possible to divorce completely the specific effects of pressure on recovery from the effects of rate of production on recovery and from all of the auxiliary factors that are affected by the interrelationship between the average reservoir pressure, the distribution of reservoir pressure, and the withdrawal rates.

The conditions necessary for efficient recovery in a water-drive reservoir, including proper regulation of the production rate, have been reviewed in some detail in prior chapters. If water drive is the proper recovery method for a particular reservoir, then maintenance of pressure is a necessary condition for most efficient recovery, for without pressure maintenance by water drive the recovery would be dominated by other mechanisms.

The specific effects of pressure itself, as distinct from pressure maintenance, are dependent chiefly on the effects of reservoir pressure on the characteristics of the reservoir fluids and the effects, in turn, of these characteristics on flushing efficiency. The pertinent characteristics of the reservoir oil that change with pressure are the viscosity, the shrinkage, the density, and the interfacial tension.

Each of these factors has a specific effect on the recovery of oil by water drive. The increase in the viscosity of the oil attending decline of reservoir pressure either decreases the amount of oil displaced by a given volume of water or increases the volume of water required to reduce the oil saturation to a particular value. The viscosity of a reservoir oil initially saturated with gas will usually increase about threefold when the reservoir pressure is reduced to atmospheric pressure.

The shrinkage of the reservoir oil does not directly affect the flushing efficiency, but it changes the amount of unrecovered oil left in a reservoir. This is so because more oil and less dissolved gas are contained in a barrel of residual reservoir oil at reduced pressure. For example, if the oil initially contained in a reservoir has a formation volume factor of 1.50, then a barrel of reservoir oil at the original reservoir pressure contains only two-thirds of a barrel of stock-tank oil. If the reservoir were flushed by water drive to an average residual oil saturation of 30%, then the unrecovered oil would represent a residual saturation of only 20% surface oil if the flushing were conducted at near the original reservoir pressure. However, the same residual saturation of 30% reservoir oil would represent a residual saturation of around 27% surface oil if the reservoir pressure had been reduced so low that the flushing was carried out when the oil had a formation volume factor of only 1.10.

The density of the reservoir oil affects the displacement only when the flow is non-horizontal and is conducted at such a rate that gravity or buoyancy contributes to the displacement. The increase in density of the reservoir oil that results from decline of reservoir pressure and loss of dissolved gas reduces the density difference between the oil and the water and reduces the buoyancy by an equivalent amount, thereby reducing the degree of oil displacement at and behind the advancing water-oil boundary.

The water-oil interfacial tension is effective at low displacement rates in bringing about completeness of flushing in a heterogeneous formation of variable texture in that it causes the water to invade and expel the oil from sections of low permeability instead of bypassing them. To the extent that the oil-water interfacial tension is reduced by reduction of reservoir pressure the driving force causing water to invade areas of low permeability is directly reduced.

Each of the effects described is the result of loss of dissolved gas from the reservoir oil when the reservoir pressure is reduced. The effects, therefore, are obviously confined to reservoir oils containing an appreciable quantity of dissolved gas, and are not applicable to undersaturated oils unless the reservoir pressure is reduced below the saturation pressure. These effects may become very pronounced in deep reservoirs that contain saturated oil with a great deal of dissolved gas.

It is not possible to express in a single general statement the magnitude of the loss of ultimate oil recovery that might result from reduction of reservoir pressure. For a particular reservoir the specific effects of pressure on the pertinent characteristics of the reservoir oil may be determined experimentally by the methods outlined in Chapter IV. The specific effects of viscosity, density, and shrinkage on the relative flow of oil and water may be calculated from fundamental equations of fluid mechanics provided adequate information is available on the characteristics of the producing formation. Methods have not yet been developed for quantitative evaluation of the effects of changes in interfacial tension. Some idea of the over-all effects of reservoir pressure decline may be obtained from data collected on a number of water-drive pools by the American Petroleum Institute Special Study Committee on Well Spacing and Allocation of Production.* These data indicated an average trend of residual oil saturation with reservoir pressure decline amounting to about 18% increase of residual oil saturation when the reservoir pressure

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*Craze, R. C. and Buckley, S. E., "A Factual Analysis of the Effect of Well Spacing on Oil Recovery," A.P.I. *Drilling and Prod. Practice* 1945, p. 144.

decline was increased from 20% to 100% of the initial reservoir pressure. Actual loss in terms of surface oil would of course be increased still further by the corresponding change in shrinkage.

With Artificial Water Drive

It is probable that when reservoir pressure is maintained by the use of water injection to supplement a natural water drive the considerations involved in the effects of pressure maintenance on ultimate recovery are substantially the same as those for maintenance of pressure by natural water drive, except for the modified relationship between the reservoir pressure and the rate of influx of water. When a water drive is created entirely by water injection there is no natural relationship between the reservoir pressure and the withdrawal rate. In such an instance the degree of maintenance of reservoir pressure depends solely on the relative amount of water injected. This is particularly true when a pattern water flood is employed, wherein injection wells are interspersed among the producing wells. In this situation the effects of pressure and of rate may be divorced entirely, and the question of the effects of pressure alone may be analyzed separately. The basic problem is in essence reduced to the question of whether there is any advantage in carrying out an artificial water flood while the reservoir pressure is high, as compared with production of the reservoir first by dissolved-gas drive, followed by an artificial water flood at low reservoir pressure.

For this specific alternative, both physical effects and economic effects must be considered. If the alternative is based on the supposition that the two operations differ only in the pressure level, and that the well pattern, the injection rates, and all other factors are the same, then the effects of pressure are confined to the effects of the changes in viscosity, density, shrinkage, and interfacial tension. The direction of these effects is such as to yield higher ultimate oil recovery when a water flood is carried on without serious decline of the reservoir pressure. The combined magnitude of the effects depends on the particular reservoir involved. Each of the effects is magnified in deep reservoirs that contain saturated oil.

The economic factors also favor the flooding operations without serious pressure decline. The chief advantage lies in a saving of operating expenses through shortening of the total time required to recover the oil. For example, if the size, shape, and characteristics of a reservoir and the manner of injection were such that fifteen years would be the proper time over which to flush the reservoir efficiently with water, the entire oil recovery operation could be concluded within fifteen years if the operation were begun soon after discovery of the reservoir and were carried on from the beginning. If, on the other hand, the reservoir were first produced for five or ten years by dissolved-gas drive and were then flooded for fifteen years, the total operation would be stretched to twenty or twenty-five years, with a proportionate increase in the total operating expense. The dual operation might also involve certain additional expenses for reconditioning of wells. In some cases these additional expenses might mean the margin of difference between profitable and nonprofitable operation, so that a deferred water flood could not be carried on at all. The only specific factor favoring a low-pressure water flood is the greater capacity of an injection well at low pressure. The additional energy required to inject water at high pressure is, however, offset by a corresponding reduction in the energy required to lift the produced oil and water. If the reservoir pressure is maintained at a high level many oil wells will continue to flow until the reservoir is substantially depleted.

Another economic factor that must be considered is that with artificial maintenance of pressure by water injection carried on from the beginning, the rate of production of both oil and gas may be stabilized at a level that will decline only gradually until the reservoir is nearly exhausted. Gathering and storage facilities, and equipment for stripping and marketing of the produced gas may be designed to fit the intended scale of the operation. If dissolved-gas drive is first employed the rates of production of both oil and gas may vary over wide ranges, and excessive capacity of equipment may be required. Much of the capacity of this equipment will be unused during the later stages of recovery by dissolved-gas drive and the early stages of the water flood. Little or no gas will be available to meet fuel requirements during the water-flooding stage.

When all of these factors, both physical and economic, are taken into account it is apparent that if the characteristics of a reservoir and its contained fluids are such that artificial water flooding is feasible and is the proper method to employ for the oil recovery then the advantage lies with starting the water injection at an early date and maintaining the reservoir pressure.

In any reservoir operated by water drive the needs of conservation are best served by preventing a serious decline in reservoir pressure.

Effect of Gas-Cap Shrinkage

A special problem arises in water-drive reservoirs in which a free gas cap is initially present. If pressure is maintained at a high level, expansion of the gas cap is prevented, and free gas production must be carefully avoided to prevent shrinkage of the gas cap and loss of oil into the region originally occupied by gas. If production of free gas cannot be avoided it may be necessary to inject the produced gas back into the gas cap. The gas injection will contribute to the maintenance of reservoir pressure to the extent that it will reduce the net reservoir withdrawals, but far more important is its function of preventing movement of oil into the gas cap. Gas injection for this purpose in water-drive reservoirs is essential in many more pools than is commonly appreciated.

Gas-cap shrinkage is most often encountered when the reservoir pressure is maintained by natural water drive at a stabilized high level. It is apparent from the facts previously explained in connection with maintenance of reservoir pressure by water drive that stabilization of pressure takes place only when the volume of water influx is equal to the total volumetric withdrawals from a reservoir; that is, when a barrel of water enters the reservoir to replace each barrel of water produced, each reservoir barrel of oil produced, and each reservoir barrel of gas produced. No expansion of reservoir fluids takes place so long as the reservoir pressure remains constant.

The magnitude of gas-cap shrinkage may be appreciated from the following example. It will be presumed that the pressure of a reservoir is maintained by natural water drive at a constant level of 2,500 pounds per square inch, that the rate of production is 1,000 barrels a day of stock-tank oil, the reservoir volume factor is 1.30, and the dissolved gas-oil ratio is 500 cubic feet of surface gas for each barrel of surface oil. It will be presumed that the actual produced gas-oil ratio is 1,500 cubic feet a barrel. There is then produced with each barrel of oil 500 cubic feet of gas that leaves the reservoir dissolved in the liquid oil and 1,000 cubic feet that leaves the reservoir as free gas. At the particular reservoir temperature and pressure involved 1,000 cubic feet of free gas occupies a volume of approximately one barrel.

If no water is produced a balance for the reservoir shows a withdrawal of 1,300 reservoir barrels of oil, 1,000 reservoir barrels of free gas, and a water influx of 2,300 barrels a day. A balance for the oil zone is particularly revealing. A total of 2,300 barrels of reservoir oil leaves the oil zone each day to make room for the 2,300 barrels of water that enters, but only 1,300 barrels of reservoir oil is produced. The other 1,000 barrels of reservoir oil is forced out of the oil zone into the gas zone to replace the 1,000 barrels of reservoir gas that is produced.

Evaluation of Loss Caused by Gas-Cap Shrinkage—As pointed out in previous chapters, it is not possible by water drive, even though it is an efficient recovery mechanism, to recover all of the oil from a formation. The average residual oil saturation in a reservoir after exhaustion by water drive frequently ranges from 20% to 40% of the total pore space. If it is assumed that 30% residual oil saturation is a typical value for a reservoir in which the pressure is maintained at a high level, then it is obvious that a comparable residual oil saturation must be left unrecovered in the invaded portion of the gas zone if water drive is employed to recover the oil from a gas zone that has been converted into an oil zone by migration of oil within the reservoir.

Very little factual information is available concerning the original oil saturation of free gas zones overlying oil. In some cases cores from the gas-bearing portion of the formation appear to contain no oil at all. In other cases they have definite staining, and sometimes they show 2% to 3% oil saturation by extraction. It is probable that the oil saturation above the transition zone of the original gas-oil contact does not exceed 5% of the pore space in most reservoirs.

If these figures are representative then it is obvious that a significant part of the oil that moves into a gas cap is not recoverable by water drive. The magnitude of the loss may be estimated in the manner outlined in the following example. If the connate water content of the gas-cap part of the formation is 30%, if it contains an original oil saturation of 5%, and if the oil moving into the gas cap displaces gas to a residual gas saturation of 10%, then the new oil has available to it only 55% of the pore space in the invaded portion of the gas zone. One reservoir barrel of migrating oil must therefore invade 1.82 barrels of pore space, increasing the oil saturation from 5% to 60%, the remainder being filled with 30% connate water saturation and 10% gas saturation. If the recovery to be anticipated by water drive is such as to reduce the average oil saturation of the oil zone to 30% then it is reasonable to expect that by later recompletion of wells to positions above the original gas-oil contact it will be possible to allow the water drive to flush the oil-invaded portion of the gas cap down to a residual oil saturation no lower than 30%. Such flushing would then yield a recovery of only 55% of the oil that invaded the gas cap, leaving 45% of it unrecovered.*

The indications are that in typical water-drive reservoirs the ultimate loss of oil that invades a gas cap usually ranges from 30% upward, sometimes reaching 100%, or complete loss. A loss of at least 50% often occurs.

A loss of 50% of the oil forced into the gas cap in the example of the reservoir producing 1,000 barrels of oil a day at a gas-oil ratio of 1,500 cubic feet a barrel at constant reservoir pressure of 2,500 pounds per square inch would indicate a loss of 500 barrels of reservoir oil or 385 barrels of stock-tank oil for each 1,000 barrels of surface oil produced. In terms of the value of the gas, the production of 1,000 cubic feet of free gas would cost 0.385 barrel of lost oil. If this oil were valued at $2.50 per barrel, each 1,000 cubic feet of free gas would cost $0.96 in terms of reduced ultimate income from oil production.

In addition to the loss in ultimate income, extra costs would be incurred in recovering the oil from the gas cap. Wells would have to be recompleted, and the recovery operations might be prolonged.

Another important factor is the effect of the production of free gas on the recovery of oil remaining within the oil zone. In the example used for illustration, wherein the oil production was 1,000 barrels a day but the water influx was 2,300 barrels a day, it is obvious that the response of the reservoir was, in respect to both reservoir pressure and flushing efficiency, the same as if the reservoir had produced at a rate of 2,300 barrels a day of reservoir oil with no free gas production. Thus, additional loss was incurred in either of two ways. If the characteristics were such that the reservoir was actually capable of yielding efficient oil displacement at a rate of 2,300 barrels of reservoir oil a day, then financial loss was caused by the unnecessary prolongation of the operation resulting from the fact that only 1,000 barrels instead of 1,770 barrels a day of surface oil was currently being obtained from the displacement. If the reservoir were actually not capable of yielding efficient displacement at a rate exceeding 1,300 barrels a day of reservoir oil, then loss of ultimate oil recovery through reduced flushing efficiency would result from the higher rate of displacement within the reservoir caused by the free gas production.

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*Recovery $= \frac{(60 - 30)}{(60 - 5)} \times 100 = 55\%$, or $= (60 - 30) \times 1.82 = 55\%$.

The losses that result from shrinkage of a gas cap in a reservoir where pressure is maintained by water drive are always so much greater than either the market value of the gas or the costs of compression and injection that free-gas production of such magnitude as to cause gas-cap shrinkage should never be tolerated in a water-drive reservoir.

In many water-drive reservoirs the production of free gas is not avoidable. The oil zone may be initially thin and may be overlain by gas over a large area, or if not initially thin, it may become thin as the recovery process approaches completion. In either event, wells must be completed eventually at or near the top of the oil interval to permit complete flushing of the oil zone by water. Exclusion of free gas from wells is often not possible under such circumstances, and injection of the produced free gas is the only feasible means of preventing a net withdrawal of free gas.

In a reservoir whose pressure is continuously declining, or whose pressure has declined to an appreciable extent before it has become stabilized, it is not always obvious from the production whether or not shrinkage of the gas cap is taking place. Under such conditions volumetric balance calculations must be employed to determine the volumetric changes taking place within the reservoir.

The impression must not be obtained that injection of gas into a water-drive reservoir is in general a desirable operation. Injection of gas to offset production of free gas is often a vital necessity for efficient recovery. It fills a specific need of stopping gas-cap shrinkage; that is its sole function. If gas were injected into a water-drive reservoir in more than sufficient volume to prevent gas-cap shrinkage, as, for example, if produced dissolved gas were returned to the reservoir, then oil would be displaced from the reservoir by gas as well as by water, and two recovery mechanisms would be operative. Such an operation would have to be analyzed on the basis of whether, in the particular reservoir under consideration, gas displacement were more efficient or less efficient than displacement by water. If displacement by water were the more effective, it would be desirable ultimately to flush the entire reservoir with water. The injection of gas might serve no purpose from the standpoint of ultimate oil recovery except to slow the advance of the water. Injection of gas into a water-drive reservoir is sometimes employed for the deliberate purpose of obtaining temporarily a higher rate of oil production than would be possible under efficient operation with water drive alone, but that is a rare practice.

GAS DRIVE

The pressure in an oil reservoir can be maintained by gas if the pore space vacated by the produced oil is kept filled with gas under pressure. The gas required may be initially present in the reservoir as a gas cap; under some circumstances it can be supplied by escape from solution in the reservoir oil; or it can be injected into the reservoir. The gas injected may be confined to that produced with the oil, or gas from extraneous sources may be supplied. The degree of maintenance of the pressure may vary from complete preservation of the original reservoir pressure to a mere retardation of the decline, depending on the supply of gas and its source.

Natural Maintenance of Pressure by Gas Cap

Complete maintenance of the original reservoir pressure by a natural gas cap is not possible, because the free gas must expand in volume to fill the space vacated by the produced oil. The required expansion is brought about by a decline of reservoir pressure. The amount by which the pressure will decline for a given volume of oil production may be determined quantitatively by volumetric balance calculations if the volumetric behavior of the reservoir oil and gas are known.

There are two essential requirements for a high degree of pressure maintenance by use of a natural gas cap. The first requirement is that the original volume of free gas considerably exceed the volume of oil to be produced; the second is that the free gas be retained within the reservoir and not be dissipated during the oil production. Fulfillment of the latter requirement requires careful control of the entire reservoir.

Since the free gas that sustains the pressure is already present in the reservoir and does not have to flow into it from a distance, the rate of production of oil does not affect the average reservoir pressure except insofar as it may cause dissipation of free gas. Maintenance of pressure requires that the oil production rates of individual wells be sufficiently restricted to avoid local irregularity of the advance of free gas and that the oil production be confined at any time to those wells not yet reached by free gas. Wells invaded by free gas must be closed in. Production of free gas inevitably sets in when the advancing gas has reached the structurally lowest wells; thereafter the reservoir pressure will decline in proportion to the volume of free gas produced as well as in proportion to the volume of oil produced.

It is apparent from the requirements for maintenance of pressure by a gas cap that they are identical with those outlined in Chapter VI for operation with a gas-cap drive. In fact, a gas-cap drive can operate only to the extent that a free gas cap can be made to expand and to encroach progressively through the oil zone. If the reservoir conditions and the operating controls are such as to yield efficient oil recovery by gas-cap drive the reservoir pressure can usually be maintained at a reasonably high level by a gas cap throughout the duration of the recovery operation. If the volume of free gas originally available is deficient, or if the available gas is dissipated by improper production practices, the retardation of pressure decline will be quite temporary.

Maintenance of Pressure by Gas Injection

Maintenance of reservoir pressure by injection of gas is not subject to the limitations encountered when pressure maintenance is confined to the effects of a gas cap initially present. The degree of pressure maintenance is dependent directly and solely on the amount of gas injected. If the gas injection is confined to the gas produced with the oil the reservoir pressure will decline continuously, but usually only moderately; if gas from an extraneous source is injected in such quantity that the reservoir volume of injected gas is equal to the reservoir volume of all withdrawals the reservoir pressure will be maintained at its original value. The exact degree of pressure maintenance obtainable by gas injection in a closed reservoir may be calculated directly by a volumetric balance.

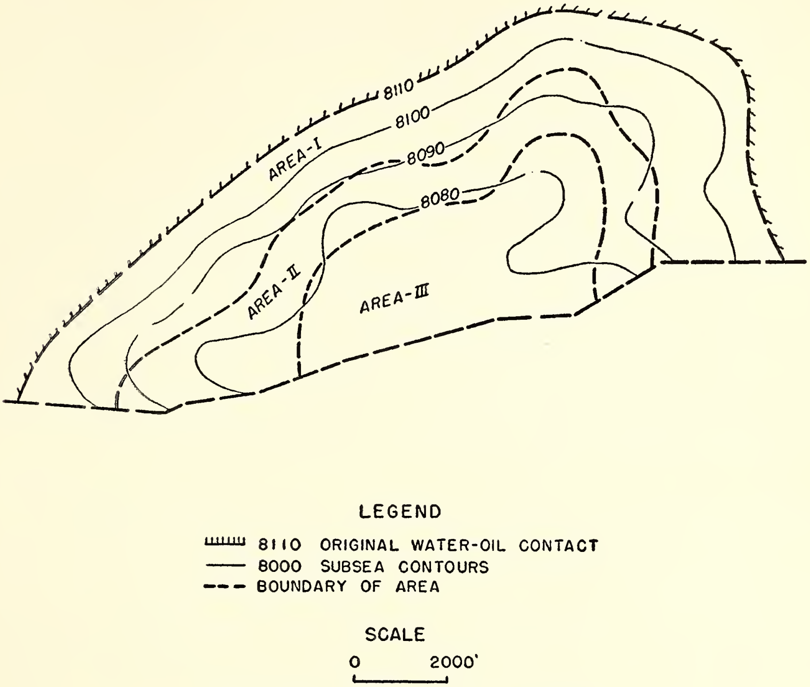
Gas-injection operations are carried on in several different ways and for several purposes. Gas produced with the oil is frequently injected into the crest of a structure to create a gas cap, to augment a gas cap already present, or sometimes merely to avoid the dissipation of free gas produced from the reservoir along with the oil. Gas may be injected at either high or low reservoir pressure through wells interspersed among the producing wells.

Maintenance of Pressure by Gravity Segregation of Dissolved Gas

To the extent that a dissolved-gas drive may be modified by causing the gas released from solution to segregate within the reservoir by buoyancy under the action of gravity, some degree of pressure maintenance may be obtained through control of the production rate in a dissolved-gas-drive reservoir, provided dissipation of the segregated gas is avoided. Although such segregation and its accompanying gravity drainage of oil can materially increase the oil recovery, the degree of maintenance of reservoir pressure possible through this mechanism is usually substantially less than with a gas-cap drive or with gas injection. Observation of gas segregation within a reservoir operating under dissolved-gas drive is important chiefly in providing direct indication that the reservoir may be suitable for gravity drainage under pressure maintenance.

The detection of gas segregation requires consideration of the reservoir pressures and gas-oil ratios of individual wells in different positions in a reservoir. The difference in specific gravity of gas and oil is sufficiently large that in many instances gas liberated in the formation flows not to the nearest well but to the highest portions of the reservoir along a path dictated by structural and formation conditions. There it causes an increase in the gas-oil ratios of the structurally highest wells. There is sometimes difficulty in detecting gas segregation because these wells are also at the greatest distance from the water-oil contact and, if any water drive is present, will usually have the lowest pressure prevailing in the reservoir at any moment. These low pressures may also exert some influence on gas-oil ratio, obscuring the principal reason for the observed increase. When the formation has low permeability the resultant low pressure immediately around a well is usually the major cause of increased gas-oil ratio. However, in a formation of low permeability, increases in gas-oil ratio should appear over the entire reservoir rather than in just the upstructure wells, although the ratio might be slightly greater in the wells high on the structure. In a formation of high permeability, upward migration of gas freed from the entire oil accumulation is more apt to be the major cause of high gas-oil ratio in upstructure wells. No sharp demarcation can be drawn, because pressure effects and segregation effects often overlap to a considerable degree. However, careful analysis of well records will often permit detection of gas segregation if it is occurring to any important extent.

Figure 14 shows an example of a reservoir in which gas segregation was clearly evident at an early date. The reservoir has an average formation permeability of 250 millidarcys. Structurally low wells did not show an increase in gas-oil ratio even when the reservoir pressure had declined 400 pounds per square inch below the saturation pressure of the reservoir oil. At the same time, wells located high on the structure showed distinct increases in gas-oil ratio. Moreover, this difference in gas-oil ratio was noticeable when the average reservoir pressure had declined only 275 pounds per square inch below the saturation pressure. The fact that the pressure dif-



PRESSURES AND GAS-OIL RATIOS

3,670 psig. ORIGINAL SATURATION PRESSURE

OCT. 1944	Area I	Area II	Area III	Field Average
AVERAGE GAS-OIL RATIO	865	1,055	1,216	1,098
AVERAGE PRESSURE	3,400	3,388	3,380	3,389
DEC. 1945				
AVERAGE GAS-OIL RATIO	867	1,117	1,433	1,179
AVERAGE PRESSURE	3,253	3,269	3,254	3,259

Fig. 14—Effect of Structure on Gas-Oil Ratio

ference between the areas of high ratio and low ratio never exceeded 20 pounds per square inch clearly indicates that migration of gas was the main factor governing the divergent behavior, even though the dip of the structure does not average more than 1%. It is particularly interesting that volumetric balance calculations on this reservoir indicated only 4.8% of the total pore space to be occupied by free gas when the reservoir pressure had been reduced 275 pounds per square inch below the saturation pressure.

Effects of Pressure Maintenance on Oil Recovery

Since the effects of the oil production rate on the reservoir pressure in a gas-drive reservoir are confined entirely to those taking place within the oil reservoir, the specific effects of pressure maintenance on oil recovery by gas drive are somewhat more readily isolated for analysis than are the effects of pressure maintenance by natural water drive. If the nature of the reservoir is such that the force of gravity can be effectively employed in the oil recovery process, the rate of oil production controls the degree of gas segregation, the uniformity of gas encroachment, the amount of oil recovery prior to the stage at which excessive production of free gas begins, and thus the relative duration of pressure maintenance. Too high a rate of oil production may cause premature production of gas and bring an end to the pressure maintenance. However, if the produced gas is all returned to the reservoir the average reservoir pressure is the same for the same total amount of oil production regardless of how fast the oil is produced. Furthermore, if the nature of the reservoir is such that the force of gravity is not an important factor it is doubtful whether the total rate of oil production has any important effect on the relative production of gas.

If gas injection is to be employed the producer has the choice of conducting a gas-drive operation at either high or low reservoir pressure at either a high or low production rate. To the extent that the rate of production of oil may have an independent effect on the ultimate recovery of oil at either high or low pressure, and to the extent that the rate of production may affect the feasibility of returning to the reservoir all produced gas, the production rate may affect both the degree of pressure maintenance and the ultimate oil recovery. Also, the degree of pressure maintenance will affect the ability of a reservoir to support a particular rate of oil production. It is these interrelations and their effects on the economics of the operation that to a large extent determine the net effect of pressure maintenance on ultimate oil recovery by gas drive.

With Gravity Drainage

When gas-cap drive is employed efficient recovery requires that the oil displacement be effected insofar as possible by gravitational drainage of the oil rather than by expulsion with gas. The degree of recovery obtainable by use of the force of gravity is dependent on the rate of oil drainage, in that adequate time must be allowed to permit the drainage to deplete the reservoir to a satisfactory degree. If the reservoir conditions are such that gravity drainage is reasonably rapid the permissible withdrawal rate for a given degree of ultimate recovery will obviously be higher than if the reservoir conditions or the nature of the oil are such that the drainage takes place more slowly. In the latter case more time must be allowed to deplete the reservoir. The specific effects of pressure on the ultimate recovery are, therefore, primarily those that affect the rate of drainage of the oil and thereby the completeness of the drainage attained by the time the operation has reached its economic limit.

In any particular reservoir the rate of drainage of the reservoir oil by gravity is directly proportional to the density of the oil and inversely proportional to its viscosity. It is also quite dependent on the oil saturation, in that the permeability of a formation to oil decreases rapidly with decreasing oil saturation. When the reservoir pressure is reduced and dissolved gas escapes from solution the density and the viscosity of the reservoir oil both increase, and the reservoir oil shrinks in volume, reducing the oil saturation.

The changes in the viscosity and in the density have opposite effects on the rate of drainage, the density increase tending to accelerate it and the viscosity increase tending to slow it down. The magnitudes of these two changes are such, however, that the increase in viscosity is always greater than the increase in density. The combined effect of these two factors is therefore to retard oil drainage when the reservoir pressure is reduced. In a reservoir containing a typical saturated oil the net retardation of the drainage rate caused by the combined effects of the changes in viscosity and density that result from reduction of the reservoir pressure from the saturation pressure to atmospheric pressure usually varies from about twofold to about fourfold.

The additional retardation caused by shrinkage of the reservoir oil varies more widely. The amount of the shrinkage varies with the amount and composition of the gas originally dissolved in the oil; furthermore, the change in reservoir-oil saturation that results from shrinkage depends on the volume of oil contained within the formation and therefore on both the connate water content and the degree of depletion. For example, if the connate water content of a formation is 20% and the oil saturation at a particular stage of depletion is 60%, a change of formation volume factor from 1.50 to 1.05 would cause the oil saturation to decline from 60% to 42%. However, if the connate water content of a formation were 40% and the oil saturation 30% at a particular stage of depletion, a change of formation volume factor from 1.20 to 1.05 would cause the oil saturation to decrease only from 30% to 26.2%. In most sandstone formations a reduction of 10% in oil saturation will cause a reduction in permeability to oil ranging from about 1.5 fold to 4 fold. The reservoir oil at the reduced formation volume factor undergoes less additional shrinkage in passing from the reservoir to the surface; accordingly, the net rate of drainage in terms of stock-tank oil is not reduced in direct proportion to the reduction in the rate of drainage of reservoir oil. However, the loss of permeability that results from the reduced oil saturation caused by shrinkage of oil in the reservoir is always great enough to cause the net effect of shrinkage to be a reduction of the rate of drainage of either reservoir oil or oil as measured at the surface.

It is obvious that the net effect of a reduction in reservoir pressure is always to retard drainage of the oil. The degree of retardation, however, will depend on both the formation characteristics and the nature of the reservoir oil. For any particular reservoir the effect may be determined provided the proper factual information is available on the producing formation and its contents.

In addition to the retardation of drainage caused by reduction in pressure, the effect of the increase in surface tension that accompanies reduction in pressure is to cause a higher retention of oil in areas of lower formation permeability. However, methods have not yet been developed for quantitative evalution of that effect.

In most reservoirs the over-all effects of pressure reduction are such as to cause an almost drastic decrease of the rate of gravity drainage of oil. These effects may be readily visualized through a specific example. It will be presumed that a particular reservoir contains 30% connate water and 70% reservoir oil, which is saturated with gas at an original pressure of 3,500 pounds per square inch and has a formation volume factor of 1.50, a reservoir density of 40 pounds a cubic foot, and a viscosity of 1.0 centipoise. It will be presumed that the dip of the formation and the permeability are such that gravity drainage will reduce the average residual oil saturation of the reservoir to 30% of the pore space by the time the rate of drainage of the oil has declined to the economic limit and free gas has reached the lowermost wells. It will be presumed that this process requires a total elapsed time of 20 years when conducted without decline of reservoir pressure. The conditions specified lead to an ultimate recovery of 57% of the oil originally contained within the reservoir.*

Alternatively, it will be presumed that the reservoir is first produced by dissolved-gas drive and that the gas is dissipated until the reservoir pressure is reduced to only slightly above atmospheric pressure. It will be presumed that this reduction of pressure will cause the viscosity of the reservoir oil to increase to 3.7 centipoises, the density to increase to 50 pounds a cubic foot, and the formation volume factor of the remaining reservoir oil to decline to 1.05. After depletion by dissolved-gas drive, gravitational drainage will continue.

The combined effects of the presumed changes of viscosity and density are such that at the reduced pressure the rate of gravity drainage will be only one-third the rate at the higher pressure for any particular remaining oil saturation. The effect of the shrinkage, however, is such that if the same ultimate oil recovery is to be obtained by gravity drainage at the reduced pressure the residual oil saturation in the reservoir will have to be reduced to 21% instead of to 30%. This will cause an additional retardation of about two-fold. To attain the same final recovery by gravity drainage at the reduced pressure would therefore require that the entire operation consume some 100 years, and that it be continued down to a final production rate of approximately one-fifth the rate at which it was presumed that abandonment would occur with the high-pressure operation.

It is quite obvious that the total costs of operation over a period of 100 years would far exceed the total for 20 years. The use of 100 years to obtain the same ultimate recovery that could have been obtained in 20 years would be economically unsound.

It is almost equally obvious that in this reservoir it would not be feasible to carry on the operation for 100 years. If abandonment at high pressure would have to occur when the rate of production of oil had declined to the economic limit, the same economic limitations would prevent a low-pressure operation from being carried beyond the time when approximately the same rate of production would be reached. In order to have the same final rate of production as would be obtained at the higher pressure at a residual oil saturation of 30% the reservoir would have to be abandoned at a residual oil saturation of at least 40% at the lower pressure to offset the retardation caused by the viscosity increase. Abandonment of the reservoir at a final oil saturation of 40% with a reservoir oil formation volume factor of only 1.05, instead of abandonment at a final oil saturation of 30% with a formation volume factor of 1.50, would mean a reduction of ultimate recovery from 57% of the original oil content of the reservoir at high pressure to only 18.2% at the reduced pressure.* The latter would represent very little increase over that obtainable by dissolved-gas drive.

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*Recovery $= \frac{70 - 30}{70} \times 100 = 57\%$

Although the magnitude of the loss in any particular reservoir may differ substantially from that of the example used for illustration, the net effect of all of the factors involved is such that reduction of reservoir pressure will always cause a loss in the ultimate quantity of oil recoverable by gravity drainage. When a reservoir is suitable for employment of this recovery method the advantages of maintaining reservoir pressure are usually quite great.

Recovery of oil by gravity drainage under pressure maintenance is in effect simply a gas-cap drive except that the gas is used solely to maintain the pressure instead of to displace the oil by forced migration. The conditions and controls necessary for this type of operation have been described in detail in Chapters V and VI. The process is essentially the same regardless of whether the gas cap is initially present or is augmented or created by injection of gas. Even when gravity cannot be employed as the sole agency for oil recovery it may contribute materially to the recovery obtainable by gas displacement. To the extent that gravity is operative at all its contribution to the ultimate oil recovery is very dependent on the maintenance of reservoir pressure to facilitate drainage of the oil.

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*Original stock-tank oil in reservoir = 70/1.50 = 46.6
Residual stock-tank oil in reservoir = 40/1.05 = 38.1

$$\text{Recovery} = \frac{46.6 - 38.1}{46.6} \times 100 = 18.2\%$$

In any gas-drive reservoir in which gravity is either the dominant force causing oil movement or is an important factor the advantages of pressure maintenance are usually sufficiently great to justify injection of gas unless there is originally present a very large gas cap that can maintain the pressure at a high level without injection. When gravity is a dominant factor the gas-injection costs can usually be kept very low, for the segregation of oil and gas within the reservoir can be employed to prevent production of gas, and the injection can be confined to the dissolved gas released from the produced oil, or to sufficient gas from an outside source merely to replace the reservoir volume of oil produced.

There are three alternatives with regard to the rate of production of oil in a gravity-drainage operation under pressure maintenance, as follows:

1. The rate of production may be restricted from the beginning to a value sufficiently low to assure satisfactorily complete drainage of the entire reservoir by the time free gas reaches the lowermost wells. Under this condition the production rate may be kept constant throughout the operation, and production of free gas should not become excessive until the entire oil zone has been substantially depleted and free gas has reached the lowermost wells.

2. The production rate may be restricted at any time to the drainage rate at the prevailing oil saturation in the uppermost part of the oil zone. This drainage rate constantly declines as the reservoir is depleted and as the formation permeability to oil is reduced by the oil desaturation. This is the maximum rate at which oil can be produced without causing premature production of free gas.

3. The oil may be produced continuously at a higher rate than the gravity drainage rate. At this rate gas will force its way into the oil zone faster than the oil can drain by gravity, and a part of the oil will be produced directly by gas displacement. Since at this rate gas will quickly penetrate the entire reservoir, free gas will be produced with the oil and the pressure can be maintained only by injection of gas.

The proper choice in a particular reservoir is dependent on whether gas is injected or whether pressure is maintained by a free gas cap initially present. In any case, the operation should be so conducted as to permit the maximum ultimate recovery of oil by the time the economic limit is reached.

With Horizontal Gas Drive

When gas drive at either high or low pressure is employed under conditions where drainage of oil by gravity cannot take place or is negligible, as, for example, when the flow is essentially horizontal or the formation permeability is low, the mechanism of the oil recovery is distinctly different than with gravity drainage.

Without the aid of gravity the gas drive is reduced to a simple displacement of oil by gas and is subject to all of the limitations imposed by the relative ineffectiveness of gas as a displacement agent. The gas invades the entire reservoir and reaches all producing wells long before the ultimate oil recovery is obtained. The final recovery obtainable is therefore determined under conditions where both gas and oil are flowing rather than just oil. If a high degree of recovery efficiency is to be reached there must be a prolonged period of operation during which the volume of gas produced far exceeds the volume of oil produced.

The basic considerations under this condition are the same regardless of the manner in which the gas drive is conducted, whether it takes place as a result of expansion of a gas cap already present or as a result of gas injection. There are no fundamental differences whether gas is injected into a gas cap or into wells interspersed among the producing wells. Since the displacement process is essentially the same regardless of the source of the gas or the manner of its injection, any gas-drive process employed under conditions such that gravity is not a factor is considered in this discussion to be a horizontal gas drive.

Certain conclusions are readily apparent from the fundamental nature of the gas-displacement process:

1. It is evident that in any reservoir in which gas drive is employed under conditions that preclude the use of gravity to cause selective oil movement the oil recovery obtainable is independent of the rate of oil production, except insofar as the rate of production affects the controlling economic factors.

2. The volume of gas that must be produced to recover the oil is so great that even a relatively large original gas cap cannot supply sufficient gas to continue a horizontal gas drive to a high degree of oil recovery unless the produced gas is returned to the reservoir. Therefore, gas injection is essential to this type of gas drive, whether it be conducted at high pressure or at low pressure.

3. Any gas-injection operation must cease when it has reached its economic limit. Therefore, in the final analysis the economic fac-

tors control the ultimate recovery obtainable by horizontal gas drive in any particular reservoir.

There are three alternative conditions under which a horizontal gas drive may be employed, as follows:

1. The reservoir may be produced by dissolved-gas drive until the reservoir pressure has declined to a very low value and the oil production has reached the stripper stage or has ceased. Gas drive may then be employed at low reservoir pressure. When so employed, the gas-drive operation is usually considered to be secondary recovery.
2. All produced gas may be returned continuously to the reservoir, beginning with the first production or shortly thereafter. This type of operation is typical of what is normally considered to be pressure maintenance during primary production.
3. Gas from an extraneous source may be injected to maintain the reservoir pressure at its initial value throughout the production process.

The latter two of these processes will be considered to be pressure maintenance.

Physical Differences Between Low-Pressure and High-Pressure Gas Drive—There are two very important differences between low-pressure and high-pressure horizontal gas drive. These are the rate of production of oil from a well and the produced gas-oil ratio. With either pressure condition the rate of production of oil from a well continuously declines and the produced gas-oil ratio continuously rises. However, at high pressure both the well-production rate and the gas-oil ratio are usually manyfold greater at any given stage of reservoir depletion than at low pressure. These facts are readily apparent from the nature of the displacement process and the effects of pressure gradient on the flow of oil and gas.

The low rate of production from a well with low-pressure gas drive is caused by the following factors:

1. The reduced reservoir pressure.

The lower the reservoir pressure at which the gas drive is conducted the lower is the pressure difference available between the reservoir and the well bore to cause flow of oil into a well.

2. Decreased formation permeability to oil.

The permeability to oil of any formation depends on the oil saturation. If the low-pressure gas drive has been preceded by dissolved-gas drive the oil saturation and the formation permeability to oil have been reduced by both removal of the produced oil and shrinkage of the oil remaining in the reservoir.

3. Increased viscosity of the reservoir oil.

The increased oil viscosity that results from the loss of dissolved gas caused by the reduction of reservoir pressure decreases the rate at which oil can flow into a well.

The combined effect of these factors is such as to bring the production of any well down to a few barrels a day by the time the reservoir pressure has reached a low level.

If low-pressure gas drive is begun after the production rate of the wells has already been reduced to a few barrels a day by dissolved-gas drive, then the operation must continue at the same low rate from a well unless the reservoir pressure is raised. The flow of gas through the formation can do nothing to increase the productivity of a well unless conditions within the reservoir are changed. The mere flow of gas does nothing to improve the conditions in regard to the flow of oil; the viscosity of the oil is not reduced; the oil saturation is not increased; and, to the extent that further desaturation of oil takes place if any additional oil at all is produced, the ability of the reservoir to deliver oil is still further impaired.

The only factor remaining that can in any way affect the rate of flow of oil is the effective pressure difference between the reservoir and the well bore. The conclusion is apparent that, aside from certain transient effects that may result from a change in the distribution of the reservoir pressure in the region immediately tributary to a well, injection of gas can sustain a higher rate of production of oil only to the extent that it is used to raise the reservoir pressure and thereby to increase the pressure differential available to drive oil to a well bore.

Reservoir pressure cannot be increased without at the same time causing an increase in the produced gas-oil ratio. The higher the pressure the greater is the resultant gas-oil ratio. In spite of any increase of reservoir pressure, the rate of production of oil will again decline continuously because of decreasing permeability to oil as further desaturation of the reservoir results from further oil depletion; at the same time, the produced gas-oil ratio will rise continuously because of increased formation permeability to gas as the gas saturation in the reservoir rises. If the tendency of the gas-oil ratio to increase is countered by permitting the reservoir pressure to decline, the decline in the rate of production of oil is merely accelerated.

It is apparent from these considerations that gas drive at low pressure is, in effect, always a stripper operation. Well-production rates are of necessity quite low.

Pressure maintenance by gas injection is an operation with a wholly different character, provided it is actually carried to its economic limit at high pressure. If reservoir pressure is maintained by gas injection the viscosity of the oil does not materially increase, the usable pressure differential for forcing oil from the reservoir into a well bore is sustained, and the oil remaining in the reservoir does not shrink materially, so the productive capacity of a well declines only as the result of the decline of formation permeability to oil as the reservoir is depleted. The high reservoir pressure, however, causes the produced gas-oil ratio to be manyfold higher than is the case with low-pressure gas drive. Thus, pressure maintenance by gas injection is characterized by sustained well capacity but by extremely high gas-oil ratio.

The reason for the much higher produced gas-oil ratio with high-pressure gas drive lies in the compressibility of gas. The viscosity of gas does not change materially with pressure, but its volume varies inversely as the pressure. A given weight of gas at 1,500 pounds per square inch occupies only 1% of the volume it would occupy at atmospheric pressure. Therefore, for any given formation permeability to gas and any given pressure gradient within the reservoir 100 times as much gas will flow at a reservoir pressure of 1,500 pounds per square inch as will flow at atmospheric reservoir pressure. This effect of the compressibility of gas is so great that it far exceeds the viscosity and shrinkage effects that act to facilitate the flow of oil at high reservoir pressure, except in those reservoirs that have oil with abnormally high shrinkage.

However, the higher the reservoir pressure at which a low-pressure gas drive must be conducted in order to yield reasonable well-production rates, the lower is the contrast between the gas-oil ratio at low pressure and at high pressure. For example, the density of gas at 3,000 pounds per square inch is approximately 200 times what it is at atmospheric pressure, but only 20 times the density at 200 pounds per square inch, and only 6 times the density at 500 pounds per square inch. Thus, when comparison is made between moderate pressure and high pressure the difference in gas density may be more than compensated by viscosity and shrinkage effects, even with normal reservoir oils, so that in some reservoirs a lower produced gas-oil ratio may be obtained by gas drive at high reservoir pressure than at intermediate reservoir pressure.

In any event, whether the gas drive be conducted at low pressure, at intermediate pressure, or at high pressure, the production of oil and gas will follow the same basic pattern. The oil-production rate of a well will decline continuously as the formation permeability to oil is reduced by depletion, and the gas-oil ratio will rise continuously as the gas saturation in the reservoir rises and the formation permeability to gas increases. If the reservoir pressure is maintained constant at either low or high pressure throughout the process the rate of decline of the oil production and the rate of rise of the gas-oil ratio are controlled entirely by the changes in formation permeability caused by depletion of the oil. If the reservoir pressure is declining during the process the decline of the rate of production of oil is accelerated by the viscosity increase of the oil and the decreased oil saturation resulting from shrinkage of the reservoir oil. Under either condition the rate of production of gas from a well usually rises as depletion proceeds, the progressive increase of gas-oil ratio more than compensating for the decrease in the rate of production of oil unless the reservoir pressure is declining very rapidly.

Economic Factors—Because of the widely different character of low-pressure and high-pressure gas drive it is not possible to choose between them on any presumed basis of efficiency.

The only obvious fact is that injection of gas at either low or high pressure will result in additional oil recovery over that obtainable by dissolved-gas drive. The real test, however, is how much additional ultimate oil recovery either process can yield by the time continued operation becomes impractical because of prohibitive costs.

The two dominant items that affect the economic limit and thus set the point at which the injection of gas must cease are the declining production of a well and the continuously increasing gas-oil ratio. The declining production reduces the income available to support the process, and the rise of gas-oil ratio leads to continuously rising costs. When the operating costs continuously exceed the revenue the operation must cease.

Some idea of the contrast between low-pressure and high-pressure horizontal gas drive and of the factors that control the economic limit of each may perhaps be obtained from the tabulations presented in Table 14. The figures in this tabulation were based on the estimated behavior of a sandstone reservoir of formation-permeability characteristics favorable to the displacement of oil by gas. It was presumed that the reservoir initially contained 30% connate water and 70% reservoir oil. The oil was presumed to be saturated with dissolved gas at 2,500 pounds per square inch, with a formation volume factor of 1.30, and a dissolved gas-oil ratio of 500 cubic feet for each barrel of surface oil.

Three situations are compared in the tabulation, as follows:

1. The reservoir is first produced by dissolved-gas drive, which is then followed by gas drive at an average reservoir pressure of 60 pounds per square inch.
2. From the beginning, all produced gas is returned to the reservoir, with fuel from other sources used for gas compression.
3. From the beginning, gas from outside sources is injected to maintain the reservoir pressure continuously at 2,500 pounds per square inch.

In each of the pressure-maintenance operations it was presumed that the production of a well is arbitrarily restricted by limiting the pressure differential between the reservoir and the well bore to 200 pounds per square inch.

TABLE 14

Comparison Low-Pressure and High-Pressure Horizontal Gas Drive

Cumulative Oil Production	Gas Drive at 60 lbs./sq. in.			Pressure Maintained with All Produced Gas Returned				Pressure Maintained at 2,500 lbs./sq. in.		
% of Original Oil in Place	Oil Production Rate bbl. per day per well	Gas-Oil Ratio cu. ft. per bbl.	Daily Gas Production cu. ft. per well	Reservoir Pressure lbs. per sq. in.	Oil Production Rate bbl. per day per well	Gas-Oil Ratio cu. ft. per bbl.	Daily Gas Production cu. ft. per well	Oil Production Rate bbl. per day per well	Gas-Oil Ratio cu. ft. per bbl.	Daily Gas Production cu. ft. per well
0........				2,500	300	500	150,000	300	500	150,000
10........				2,020	202	850	170,000	230	900	210,000
20........				1,790	134	2,000	270,000	168	1,800	300,000
30*.......	10	1,300	13,000	1,640	87	6,000	520,000	115	4,900	560,000
40........	6.5	3,600	23,000	1,530	55	18,000	990,000	75	16,000	1,200,000
50........	4.2	10,000	42,000	1,390	33	55,000	1,800,000	46	52,000	2,400,000
55........	3.2	16,000	51,000	1,340	25	95,000	2,400,000	35	97,000	3,400,000
57........	2.9	20,000	58,000	1,320	22	125,000	2,750,000	31	125,000	3,900,000

*Assumed final recovery by dissolved-gas drive.

This tabulation was prepared for the sole purpose of comparing high-pressure and low-pressure gas drive, rather than to represent actual rates of production and gas-oil ratios to be anticipated at the indicated stage of depletion in any particular reservoir. In an actual reservoir the formation permeability might be much higher or much lower than that used in the illustration, and the permeability-saturation relations of the formation might be more favorable or less favorable for displacement of oil by gas, leading to a higher or lower degree of depletion at the time the indicated gas-oil ratios are reached. However, in spite of these limitations, certain conclusions might be permissible from the analysis. These are briefly as follows:

1. Gas drive at low pressure will nearly always be characterized by a low and continuously declining rate of production of oil per well, and by gas-oil ratios that continuously increase toward moderately high values.

2. Maintenance of pressure by gas drive will usually permit much higher rates of production per well than at low pressure, will result ultimately in very high gas-oil ratios, and will require large injection capacity if depletion of the reservoir is to be carried to a high percentage recovery of the oil in place.

3. Pressure maintenance will permit depletion of a reservoir with far fewer wells than gas drive at low pressure. For example, if, in the reservoir for which the data are tabulated, a total elapsed time of 20 years were required to obtain the ultimate recovery from a 40-acre lease with one well with the pressure maintained at 2,500 pounds per square inch, the same property would have to be developed with 11 producing wells in order to obtain the same ultimate recovery within 20 years by low-pressure gas drive.

4. Pressure maintenance will usually permit the wells to flow until abandoned, whereas gas drive at low pressure will almost invariably require that all wells be pumped.

5. The economic limit at low pressure will often be controlled primarily by the costs of operating the wells rather than by the costs of gas injection. For example, if it should cost $3.00 a day for each producing well to maintain production and $0.01 for each thousand cubic feet for gas compression, costs for each barrel of oil at a production rate of 2.9 barrels a day at a gas-oil ratio of 20 thousand cubic feet a barrel would be $1.04 a barrel for well operation and $0.20 a barrel for gas injection.

6. The economic limit at high pressure will be controlled primarily by the costs of gas injection and by the recurring need for additional investment in increased capacity for gas injection as depletion proceeds.

7. Low-pressure gas drive cannot be economically employed at all to recover the oil from a deep reservoir that requires high-cost wells. It is strictly limited to shallow reservoirs of reasonably high permeability where wells can be drilled cheaply. For example, if the reservoir used for illustration contained 400 acres, were 5,500 feet deep, and if a well cost $60,000 complete and connected to tanks, then the reservoir could be developed for high-pressure gas drive

with 10 production and 2 injection wells for a total of $720,000 for wells, plus a gas-compression plant of 40 million cubic feet a day ultimate capacity. Development for low-pressure gas injection would require approximately 110 producing wells and 110 injection wells, or a total investment of $13,200,000 in wells alone in order to obtain the same ultimate recovery within the same time. Such an investment in wells would obviously be prohibitive. Employment of fewer wells at low pressure would prolong the operation and increase the operating costs.

It is reasonably apparent from these considerations that the economic limitations of a horizontal gas drive are quite severe. Unless a reservoir is especially suited to gas drive, and unless the whole operation is well planned in advance and is carefully analyzed throughout its duration, a high degree of recovery efficiency cannot usually be anticipated. It should be noted particularly that even though high-pressure gas drive would seem capable theoretically of effecting reasonably high oil recovery, the continuously increasing gas production requires almost continuous investment in new plant capacity to obtain a continuously declining future oil production. Eventually a stage is reached at which the anticipated future oil production can no longer justify additional plant investment. When the rate of production of gas reaches the installed capacity of the plant the rate of production of oil may either be restricted to permit continued complete gas injection, at a sacrifice, thereby, of part of the advantage gained by pressure maintenance, or the gas produced in excess of the plant capacity may be dissipated. If the latter course is followed the pressure maintenance is soon ended, for dissipation of gas from the reservoir causes an immediate and rapid decline of reservoir pressure. If the operation is thereafter continued to a low reservoir pressure it may become a low-pressure gas drive, and the ultimate oil recovery may be governed by the economics of low-pressure rather than high-pressure conditions. A similar result is usually obtained if the supply of reservoir gas is used as fuel for the required compression.

If a gas-drive operation is eventually to be carried to its economic limit as a low-pressure gas drive it is difficult to see how the temporary maintenance of reservoir pressure can have any material effect on the ultimate recovery, for the ultimate oil recovery is dependent on the condition attained just prior to or at abandonment. The advantages, if any, of pressure maintenance as a purely intermediate stage of production would appear to be confined to the economic advantages that might be obtained through a higher rate of oil withdrawal and reduced costs during a portion of the operation, and the availability of gas from the reservoir rather than from outside sources for the gas drive. Under some conditions temporary pressure maintenance ending up as a low-pressure gas drive may make it possible, in effect, to obtain the benefit of low-pressure gas drive with fewer wells than if the entire operation were carried out at low pressure.

It appears that a definite advantage in the ultimate efficiency of the oil recovery can be attributed to the high-pressure gas drive only when the high-pressure operation can be continued at high reservoir pressure beyond the stage of depletion ultimately attainable economically by low-pressure gas drive. Such an advantage is possible in deeper reservoirs, where the cost of a well is such as to prohibit intensive development for low-pressure gas drive, in reservoirs that contain liquids with very high shrinkage, in fields where gas from a high-pressure gas reservoir can be injected into an oil reservoir without compression and can be marketed as it is produced with the oil, and in reservoirs whose oil content per acre is such that a gas-compression plant of very large capacity can be supported by the anticipated oil production.

Whenever compression is required for high-pressure gas drive, as it almost always is, the ultimate oil recovery obtainable is determined very largely by the size of the gas-compression plant that the pool can support. If a pool is first completely developed with wells and a decision is then made to employ pressure maintenance, the incremental production of oil to be anticipated from gas injection may not be sufficient to support a compression plant of large capacity. However, if a decision to employ pressure maintenance were reached at an early stage of the development it might then be possible to employ fewer wells for development and to invest the saving in well costs in a larger compression plant than would otherwise be justifiable, thus providing means for increasing the ultimate recovery beyond that obtainable by normal development.

Unfortunately, it has often not been realized that the higher average rates of production made possible by pressure maintenance permit the substitution of a gas-compression plant for a part of the wells in a gas-injection operation. Too frequently a pool is completely developed with a particular program of well spacing before the possible advantages of gas injection are investigated. It is then too late to use the savings from undrilled wells to install a large gas-compression plant.

In many pools, gas drive has been followed by an artificial water flood after the gas drive has become unprofitable, usually in shallow pools where the gas drive was conducted at low pressure after depletion by dissolved-gas drive. If gas drive is to be employed solely as an intermediate recovery method in a pool that can be successfully flooded by water to give a higher ultimate oil recovery it would appear that the gas drive would have no merit whatsoever, since it has no effect on the ultimate recovery finally obtained by water drive, and it increases both the total cost and the total time required to recover the oil.

However, in spite of the very obvious limitations, it is quite possible that pressure maintenance by gas injection can be more effectively used than has usually been the case. The most urgent necessity is a thorough analysis as early as possible after the discovery of a pool, and the adoption of a development pattern properly designed to obtain the maximum advantage from pressure maintenance. It is most important that such analysis be made before too large an investment has been made in producing wells. Furthermore, full advantage of pressure maintenance cannot be obtained unless an entire reservoir can be operated as a single, natural producing unit irrespective of property lines, as is the usual practice in gas cycling. Any analysis of a possible pressure maintenance program should include investigation of both water injection and gas injection. Whichever is most suitable for a particular reservoir should be employed to the exclusion of the other, as many reservoirs do not contain sufficient oil to support two successive operations. Although experience in shallow pools seems to indicate that artificial water flooding has an advantage over gas drive in many reservoirs, it is quite possible that high-pressure gas drive with a minimum of wells and very large compression-plant capacity can compete favorably if patterned after gas-cycling operations.

LIMITATIONS OF PRESSURE MAINTENANCE

It should be recognized that pressure maintenance is not feasible in all pools. Adverse reservoir characteristics sometimes impose difficulties that aggravate the economic limitations. Great variations of formation permeability, either laterally or vertically, may cause gas or water to flow primarily through limited sections of high permeability, leaving the oil undisplaced in a large part of the formation, or excessively increasing the costs of injection of gas or water. Multiple producing strata within a reservoir may also aggravate the difficulty of control, for water or gas may advance through certain strata more rapidly than through others. Difficulties arising from a multiplicity of separate strata can sometimes be alleviated through selective completion of wells within limited intervals, but even where such an expedient is possible the total costs of the operation are usually increased.

Adverse situations must be recognized and taken into account in planning a pressure-maintenance operation or in reaching a decision to employ pressure maintenance. It is not sound to presume blindly that because pressure maintenance is successful in one pool it will be equally successful in another. However, in spite of the many limitations, both economic and physical, maintenance of pressure by either gas drive or water drive can be successfully employed in many more pools than are actually being produced with pressure maintenance. The essential requirement is that the necessary factual information be obtained for each reservoir as early as possible during its development, in order that a proper decision may be reached promptly, and in order that any pressure-maintenance program installed may be designed to fit the specific characteristics of the particular reservoir involved.

It is important that it be clearly recognized that in any particular reservoir the degree of recovery efficiency obtainable by pressure maintenance is in the final anlysis directly dependent on the economic factors that limit how far the oil depletion may be carried before the process must be discontinued. A thorough cost analysis over the projected life of a project is just as essential as is determination of the physical characteristics of the reservoir. Every economy in the development or in the operation that will permit the carrying of the operation to more complete depletion of the reservoir prior to abandonment will increase the ultimate oil recovery and thus will promote conservation; conversely, improper planning, or development in such manner as will increase the total costs unnecessarily, is a direct cause of reduced ultimate oil recovery and thus a source of avoidable physical waste. Proper advance planning, and development with a minimum investment in wells are especially critical when horizontal gas drive is employed for pressure maintenance.

It is not possible to maintain the pressure in merely a portion of a reservoir, for oil, gas, and water can migrate freely through the producing formation from one location to another if a pressure difference exists. Therefore, a pressure-maintenance operation is not feasible at all unless it can be applied to an entire reservoir. Furthermore, development and operation of a reservoir with artificial pressure maintenance can be done economically only if the entire reservoir can be operated as a single, natural physical unit with production and injection wells so located, completed, and operated as to obtain the most efficient displacement of oil by gas or by water. The development and operating economies and the planning required for successful use of artificial pressure maintenance to obtain a high degree of recovery efficiency are all dependent on control of a reservoir as a single unit. The employment of pressure maintenance is therefore contingent on the feasibility of operating a reservoir as a single unit, either through planned cooperative action on the part of all owners or through unitized control.

OIL MIGRATION CAUSED BY PRESSURE MAINTENANCE

Whenever reservoir pressure is maintained by either a natural or an artificial water drive, oil is forced to migrate from one part of a reservoir to another. The direction of this movement is usually from the edge toward the structurally higher portions, or from the area underlain by water toward the region most remote from the water.

From the standpoint of recovery efficiency this forced migration of oil is absolutely essential and cannot be avoided. As was shown in earlier chapters, it is a vital element of the recovery process. It is obvious, however, that, to the extent that the ownership of a pool may be divided among a number of separate owners, oil may be transferred by this process from beneath the land of one owner to a new location beneath the land of another. Some owners may suffer loss through adverse drainage, and others may profit through receiving the benefits of the drainage.

If a pool is developed by uniformly spaced wells covering the entire area, and if all of the wells are produced, oil is produced from each of the properties, but the recovery comes selectively from the portion of the reservoir invaded by water, and depletion of the oil takes place only beneath those properties underlain by water. The effects of this situation are well illustrated in the East Texas field. The western portion of this pool was originally underlain by water, and the direction of movement of the water is from west to east. Under strict regulation of the rate of production by the Railroad

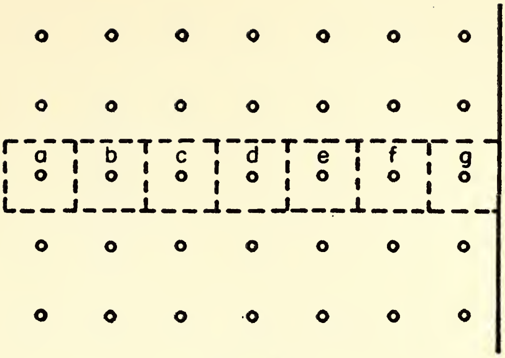
Commission of Texas (the administrative agency for the oil and gas conservation statutes), and through injection of 90% of the water produced with the oil, the reservoir pressure in this field has been continuously maintained by natural water drive above the saturation pressure of the reservoir oil except in minor areas near the eastern edge, where the producing sand becomes shaly and disappears. For all practical purposes, every barrel of oil produced from this field has been and is currently being replaced by a barrel of water influx. Properties located in the eastern one-third of the field are not yet underlain by water and still retain their original oil content, even though the pool has produced over 2 billion barrels of oil and even though those properties have been producing oil for 20 years. The oil produced from the properties in the eastern part of the field has been replaced by subsurface migration of oil from the portion of the reservoir invaded by water.

This condition is recognized by operators in water-drive pools and has led to the concept of "structural advantage," in recognition of the advantage that accrues to the owner whose property is so situated as to receive the benefit of oil migration.

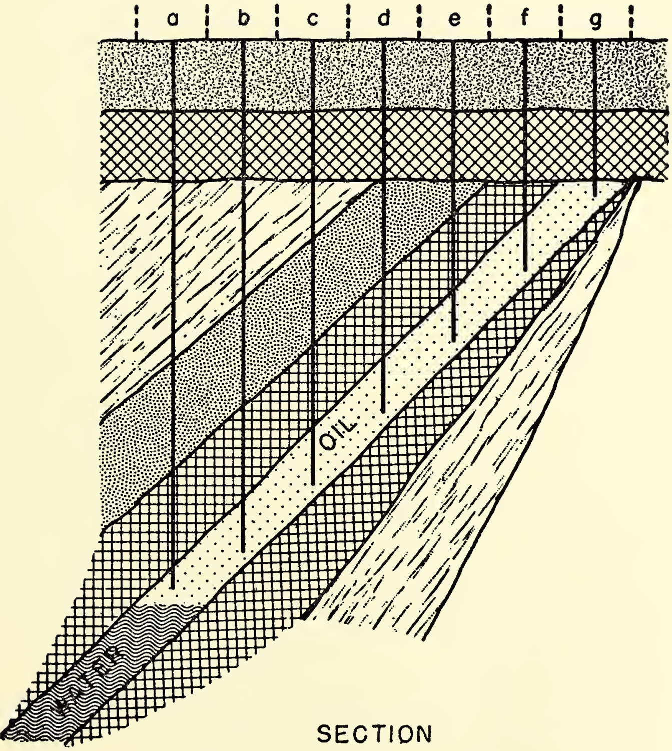
The amount of drainage suffered by one property and gained by another is dependent to a great extent on the shape of the reservoir, the dip of the formation, the continuity of permeability, the area underlain by water, and the relative rates of production of wells in various locations. When the entire oil accumulation is underlain by water, drainage from one property to another may be very slight. It is even possible under some circumstances for the outermost properties to benefit by drainage from those more centrally located.

The degree to which migration of oil may affect the ultimate recoveries from various properties is illustrated in Figure 15. In this illustration it is assumed that the pool is divided into 20-acre tracts, each with a centrally located well, that each well produces at the same rate, that the permeability of the formation is uniform in all directions, and that the rate of production is so restricted that the reservoir pressure is maintained, that water advances uniformly with a horizontal surface, and that the displacement of oil is completed at the moving water-oil interface. The following tabulation compares the calculated resultant recoveries with the amounts of recoverable oil originally underlying the various tracts.

Under the conditions assumed tract *a* recovers only 14% of its recoverable oil originally in place, but tract *g* produces over 4 times as much oil as it originally contained.



PLAN



SECTION

Fig. 15—Effect of Water Drive on Oil Migration

TABLE 15

Effect of Migration on Relative Oil Recoveries of Various Properties (Fig. 15)

Tract	Recoverable Oil in Place	Ultimate Oil Produced
a	50,000	7,000
b	100,000	24,000
c	100,000	44,000
d	100,000	69,000
e	100,000	102,000
f	100,000	152,000
g	50,000	202,000
Total	600,000	600,000

It is readily apparent that if, instead of producing at the same rate as all other wells, the wells located on those tracts that are being drained were produced at higher rates than other wells the amount of adverse drainage would be reduced. However, in many cases it would not be possible to prevent all adverse drainage except by closing in wells remote from the water, or by allowing wells near the water to be produced at greatly disproportionate rates. Excessive concentration of oil withdrawals in close proximity to the advancing water would cause irregular water invasion, would lead to reduced flushing efficiency, and, in the extreme, would cause rapid drowning out of the near-by wells, which would defeat the purpose.

All of these considerations often make it extremely difficult to arrive at an equitable distribution of the oil production in a pool produced by water drive. When the rate of production of oil is restricted by state regulation to prevent waste and the allowed production is allocated among the various properties according to some formula the difficulties of arriving at a reasonably fair system of allocation are very great.

The migration and drainage that take place within a reservoir under water drive are not the result of inherent characteristics of a reservoir or a natural consequence of oil production, but are caused by the process employed. Both the direction and the extent of drainage from one property to another would be different if, instead of water drive, dissolved-gas drive or gas-cap drive were employed to recover the oil in the same reservoir.

For example, if, in the reservoir illustrated in Figure 15, gas were injected into the crest of the structure to create a gas cap, and the reservoir were produced under pressure maintenance by gas-cap drive, the operation under properly controlled conditions might be just as efficient as if water drive were employed, but oil would drain from tract *g* to tract *a*. What was formerly a favorable structural location would become unfavorable, and what was formerly an unfortunate location would be a fortunate one. The relative recoveries of tracts *g* and *a* would again be disproportionate, the former producing far less than its oil in place, and the latter far more.

Thus, favorable and unfavorable locations refer not so much to structural position as to the relation of structural position to the mechanism employed to recover the oil from a particular reservoir. To the extent that the dominant recovery mechanism is fixed by the natural response of a reservoir to the operating controls forced by state regulations, the effects of structural position cannot be avoided insofar as a particular owner is concerned. The situation is quite different, however, when the dominant recovery mechanism is not fixed by a natural reaction of the reservoir to administrative regulation but is a free and deliberate choice exercised by the operators themselves. When the choice is deliberate, as it always is when gas or water is injected to create an artificial gas-cap drive or water drive, the resultant migration and drainage of oil are just as essential to efficient ultimate recovery, but the increased ultimate recovery that results from the injection may accrue predominantly to only a part of the properties.

For example, if, in the reservoir illustrated in Figure 15, water were injected into the lower edge below the oil to create an artificial water drive, oil would be driven from tracts *a, b, c,* and *d,* and tract *g* would receive ultimately the most benefit. Since tracts situated similarly to tract *a* are the only locations suitable for injection of water, the owners of those tracts are the only ones who could inject water to create a water drive. It is illogical to assume that they would deliberately choose to inject water to drive oil from their own properties to benefit the owner of tract *g*. Conversely, the only structural location suitable for gas injection is within tract *g* or similarly situated tracts, but it is also illogical to assume that the owner of tract *g* would deliberately inject gas to drive oil from his property for the benefit of tract *a*. Thus, an impasse is reached wherein it becomes impractical for the producers to act individually to carry on those operations that may be required to obtain efficient oil recovery, unless they can reach some agreement for sharing the benefits.

It seems fairly obvious that efficient operation of an entire pool cannot be obtained unless some method can be developed whereby the individual producers can jointly, or in cooperation with each other, pursue a common objective and carry out the particular single method of operation best designed to recover economically the highest possible ultimate recovery from each individual reservoir. Since efficient recovery always requires use of a single dominant displacement process, and since the displacement is always accompanied by migration of oil within the reservoir, the basic problem is how to remove the conflict between the ultimate gain in total recovery on the one hand, and on the other the disproportionate distribution of the total among the various owners, with actual loss to some.

The obvious remedy for this situation is for the property owners and lessees jointly to agree on the proper method of exploitation of a reservoir to obtain the maximum ultimate total recovery, and to partition the total recovery according to some agreed fair basis so that each shares equitably in the resultant gain. Such a pooling of interests to pursue a common objective in the operation of an entire reservoir is commonly called a unit-operation program or unitization. Unit operations have been adopted with spectacular success in a number of pools.

Part Two . . . GAS RESERVOIRS

Gas reservoirs differ in no respect from oil reservoirs except in the nature of the reservoir fluid. The great expansibility of gas makes efficient recovery of gas no problem, for almost all of the gas may be recovered from a reservoir by simply allowing the compressed reservoir gas to flow into a well until the reservoir pressure is exhausted.

Since pressure maintenance is not required for the efficient recovery of gas, there is no real need to maintain pressure in a dry gas reservoir or in a reservoir containing wet gas of such character that it cannot condense within the reservoir. It is only when a reservoir contains condensate, which, as explained in Chapter IV, is vaporized oil held in the gas phase by high pressure, that pressure maintenance may be required, not to recover the gas, but to recover the vaporized crude oil. If the nature of the reservoir gas is such that pressure maintenance is required for efficient condensate recovery, the pressure may be maintained by a natural water drive if the physical character of the producing formation is suitable, or the pressure may be maintained by injection of dry gas. The latter operation is known as cycling.

Even though pressure maintenance is a gas reservoir may not be required for efficient recovery, there are sometimes certain economic advantages to maintaining pressure by either natural water drive or a cycling operation.

PRESSURE MAINTENANCE BY WATER DRIVE

The physical requirements for maintenance of pressure by natural water drive are exactly the same for a gas reservoir as for an oil reservoir. The producing formation must be continuously permeable over a great distance, and there must be available an extensive aquifer to supply the water. Provided the formation characteristics are suitable the reservoir pressure may be maintained at any selected level below the original by appropriate restriction of the rate of gas withdrawal.

There are two economic considerations that under some circumstances make it advisable to use an available natural water drive to maintain the pressure in a dry gas reservoir. One is to maintain the productive capacity of the wells, the other is to deliver the gas at high wellhead pressure.

The productive capacity of a gas well declines very rapidly as the reservoir pressure is reduced. In order to reduce a reservoir to a very low abandonment pressure there must be a prolonged operation unless the formation permeability is high. For example, the open-flow capacity of a dry gas well in a reservoir initially at 2,000 pounds per square inch would decline to approximately one-fourth its initial value at a reservoir pressure of 1,000 pounds per square inch, and to only 1% of its initial value at a reservoir pressure of 200 pounds per square inch. The reason for this is that the capacity of a gas well is proportional not to the reservoir pressure but to the square of the reservoir pressure. If the original open-flow capacity of a well were of the order of 100 million cubic feet of gas a day at 2,000 pounds per square inch reservoir pressure this decline would not be of too much concern, for the well could still produce one million cubic feet a day at a reservoir pressure of 200 pounds per square inch. However, if the original open-flow capacity were only 5 million cubic feet a day the capacity would decline to around 50 thousand cubic feet a day at 200 pounds per square inch reservoir pressure.

Under some circumstances the use of a natural water drive to support the productive capacity of wells may permit more economic development of a reservoir and may facilitate processing and marketing of the produced gas. The resultant economies may even make it possible in some pools to recover by water drive a higher percentage of the gas before the economic limit of the operation is reached than would be the case with depletion of the pressure.

Maintenance of reservoir pressure by water drive is also suitable for recovery of condensate. If the physical characteristics of the producing formation are such that the reservoir pressure can be maintained at a high level by water influx at a reasonable rate of gas withdrawal, most of the condensate can be kept in the vapor phase in the reservoir and can be recovered from the produced gas at the surface. The advantage of water drive over cycling for condensate recovery is that it permits the withdrawal and marketing of gas concurrently with the recovery of condensate. In a cycling operation the withdrawal of gas must be deferred until after the condensate has been recovered.

Effect of Water Drive on Gas Migration and Drainage

If the pressure in a gas reservoir is maintained by water drive the volume of water influx is substantially equal to the reservoir volume of gas withdrawn. Migration of gas from one portion of the reservoir to another is an essential part of the process, just as is migration of oil when the pressure of an oil reservoir is maintained by water drive. The water forces gas from beneath one property to a new location beneath another, changing the relative recoveries of gas from wells on different properties. The situation is similar in all respects to that encountered in oil reservoirs.

Even though there may be no deliberate intent to maintain pressure by water drive, the nature of the producing formation may be such that water will naturally invade the reservoir in response to the pressure decline caused by the withdrawal of gas. If a natural water drive is unavoidable, as it often is, then it is just as necessary to use proper reservoir controls to obtain a high degree of flushing efficiency as is the case when water drive is the deliberately chosen method of operation.

CYCLING

Reasons for Cycling

Cycling may be employed for any of several reasons. In some areas, particularly in the southwestern part of the United States, markets for gas have until quite recently been inadequate to provide an outlet for many gas pools, and the low price offered for gas at the well has discouraged sales. Under these circumstances, cycling is often resorted to in order to obtain a revenue currently from the recovery of liquid products until such time as it is possible or advisable to withdraw gas for sale.

Sometimes a large reserve of wet gas or condensate comprises the gas cap of an oil reservoir, and withdrawal of free gas would jeopardize the recovery of oil. Cycling may be employed to obtain revenue from the gas properties until such time as the recovery of oil is complete and gas withdrawals may be permitted.

In high-pressure reservoirs in which the gas contains a large proportion of heavier hydrocarbons that may condense within the reservoir if the reservoir pressure is reduced by the production of gas, cycling is employed to recover these materials by displacing them from the reservoir in the vapor phase at high pressure. The injected dry gas maintains the reservoir pressure and thereby prevents the condensation of liquid within the reservoir.

Cycling in this type of reservoir is sometimes essential to efficient recovery of the heavier hydrocarbons contained in the gas. The concentration of these materials even in a rich gas is such that when condensed to liquid in the reservoir they fill only a very small fraction of the pore space. Unless they can be displaced while in the gas phase they cannot be recovered at all.

It should be noted that, regardless of the reason for cycling, and whether or not cycling is actually required for efficient condensate recovery, it is, nevertheless, an operation that conserves natural gas, for the gas is not consumed in the process except to a minor extent. The bulk of the gas is retained in the reservoir until such time as it may be profitably withdrawn for market.

Factors Affecting Recovery

The process of cycling does not result in complete displacement of wet gas from a reservoir; in fact, unless the characteristics of the formation are suitable for cycling the process may yield very low displacement. The basic limitations are largely geometric. At least two wells are required: one for injection of dry gas and one for production of wet gas. It is obvious from elementary considerations that at least a part of the injected dry gas will flow from the injection wells to the production wells by the most direct available paths, displacing only that gas immediately ahead of it. As soon as dry gas reaches a producing well it is produced along with the wet gas, dilutes it, and reduces the surface yield of condensate. Eventually the point is reached at which the wells produce mostly dry gas and the condensate yield is no longer sufficient to support continued operation.

It is apparent that if a high degree of recovery of condensate is to be obtained by cycling it is necessary to postpone as long as possible the invasion of producing wells by the injected dry gas so that as much wet gas as possible may be displaced from the reservoir before the production of dry gas becomes excessive. It is quite obvious that separation of the production wells and the injection wells by the greatest possible distance would be a step in the right direction. A great deal of thought has been given to the question of how best to locate the production and injection wells.

Sweep Patterns

One of the ways by which to determine the most effective well pattern for a cycling operation is by the use of electric models. Various types of models have been used; in some, the area swept out by dry gas in each stratum is determined directly by a color change that takes place in an electrolyte; in others, the progressive travel of the dry gas through a stratum and the area invaded by dry gas at any stage of depletion are determined from electric potential gradients. These methods have been used extensively and now are considered essential to the proper planning of a cycling operation. Such models are also used to control a cycling operation to obtain the utmost displacement efficiency; when dry gas first begins to appear in producing wells the swept areas are determined and the model is used to determine the adjustments of injection rates required to enlarge the swept areas.

Such models have shown that the sweep efficiency is quite dependent on the well pattern. If an improper pattern is used less than 75% of the area of a reservoir may be swept by dry gas before the production of dry gas becomes excessive. On the other hand, with properly located injection wells and production wells the sweep efficiency may be increased to as high as 90% or more. Experience has indicated that the most effective sweep patterns are usually obtained by locating the production wells at one end of a reservoir and the injection wells at the other.

Flushing Efficiency

The other important factor that controls the recovery in a cycling operation is the flushing efficiency obtained in the swept areas. Since the injected dry gas and the wet gas being displaced are completely miscible, there is no residual saturation of wet gas left behind in the manner of residual gas or oil left in pore space flushed by water. Nevertheless, subsurface formations vary in texture and permeability. The advancing dry gas will naturally tend to flow preferentially through the most permeable available channels and to detour around or only partially invade sections of reduced permeability, leaving their wet gas intact or displacing only a portion of it. In a formation with extreme variations of permeability the over-all flushing efficiency may be quite low. There is nothing an operator can do to cause efficient flushing in a formation with adverse physical characteristics. For this reason, cycling is suitable only in reservoirs that have favorable formation characteristics. For a high degree of recovery of condensate by cycling the formation must be continuous and must have reasonably uniform permeability.

Need for Operation of Reservoir as a Single Unit

Since the most successful cycling requires that the production and injection wells be located in the most advantageous positions with regard to the geometry of a reservoir rather than with regard to individual property lines, and since cycling cannot even be carried on at all with one well, an efficient cycling operation requires that an entire reservoir be operated as a single producing unit. Cycling cannot be carried on efficiently in part of a reservoir if gas is being withdrawn concurrently in another part.

Furthermore, as in the case of all other pressure-maintenance operations, cycling involves a displacement of reservoir fluids from one portion of a reservoir to another. If the injection wells are located at the opposite end of a reservoir from the production wells, wet gas is first displaced from the immediate vicinity of the injection wells and, thereafter, progressively from all intervening areas. It is obvious that such operations cannot be carried out with maximum efficiency in reservoirs that underlie a number of separately owned tracts unless the various owners pool their interests to carry out the operation jointly. Accordingly, unit operation of gas reservoirs for the purpose of cycling has become common practice.

Chapter IX

CONSERVATION AND STATE REGULATION

DEVELOPMENT OF CONSERVATION

Wasteful Practices Prior to Conservation

Control of production rate, preservation of gas caps, injection of gas and water, pressure maintenance, cycling, and the many auxiliary controls now employed to recover oil and gas efficiently have not always been in use. Oil and gas were produced for many years before such techniques were even thought of. They were simply produced by the direct process of drilling wells and producing them wide open. The objective of each producer was to drill his wells as fast as possible and to produce as much oil as possible before the pool could become exhausted. It was always a race against time and against the other fellow.

Surface waste was evident enough in the enormous volumes of gas that were blown to the air and in the oil that sprayed over the countryside from the top of a derrick. Under the conditions then existing, oil could not be retained in the ground but had to be produced. Over-production periodically flooded the market, drastically depressed prices, and brought about conditions of near chaos in the industry. The rapid production and resultant waste raised fears that our oil resources were in grave danger of being completely dissipated by wasteful practices.

Conditions Formerly Causing Waste

The root of the difficulty lay in the inevitable result of the combination of two seemingly innocuous factors. One of these was a rule of law popularly known as the rule of capture. According to this doctrine, which had been established by the courts in an early day, the owner of a well was recognized as the owner of the oil and gas that issue at the surface through his well, even though the oil and gas were drained from lands of his neighbors. This doctrine was obviously a simple rule of convenience, and one of the courts that applied it in an early case declared that a better knowledge of the facts would doubtless lead to the application of a better rule of adjusting and protecting property rights. The rule of capture merely quieted title to produced oil and gas by affirming that reduction to possession constituted ownership. It was adopted at a time when little was known of the underground character and behavior of petroleum, when it was utterly impossible to determine the ultimate source of the oil and gas produced by a well. Even today, specific identification of the original underground abode of each barrel of oil or cubic foot of gas produced by a well would be impractical.

The other part of the combination was the migratory or fugacious nature of petroleum. Even though little was known of their quantitative behavior, and although fluid mechanics as now applied was yet to be heard of, it was very well known that oil and gas were fluid substances that could and did flow from one underground location to another when a well was produced.

When the known fluid nature of petroleum was combined with the rule of capture there could be but one result. Once a reservoir had been discovered and oil was produced, the owner of the discovery well would own all of the oil he could produce and recover regardless of whether it came from beneath his own property or drained from beneath the land of his neighbors. An adjacent landowner had no recourse. If oil and gas underlay his property they would escape to his neighbor unless he reduced them to possession beforehand by drilling wells on his own property. Self-protection forced each owner of a tract of ground overlying an oil pool to drill quickly as many wells as he could and to produce each well at its utmost capacity. If he could not market his oil as quickly as it was produced, he was forced to provide surface storage, in a dammed creek or earthen pit if necessary, for only after his oil was at the surface could he call it his own and be assured of its possession. The gas produced with the oil was often flared or blown to the air.

The inevitable result is obvious. There was a tendency to deplete each pool as fast as it was physically possible for the wells to produce the oil. Drilling was continued until the declining production of old wells indicated that a new well would not recover its cost. This resulted in very close spacing of wells in rich pools and wider spacing in pools of lower yield. The density of drilling bore no relation to the number of wells actually required to recover the oil, and tremendous waste in the form of unnecessary development costs resulted.

It was obvious to many that this situation was not in the public interest, was of no advantage to the oil industry, and provided a poor and risky basis on which to depend for oil for a growing industrial economy, let alone possible national emergencies, should such ever arise. It was equally obvious that individual landowners and lessees were powerless to correct the situation, for if they refrained from drilling, or restricted the output of their wells the only result would be loss of some of their recoverable oil through subsurface drainage to others. It seemed highly questionable that concerted action to restrict production could be obtained through voluntary agreement by all the producers in a pool, or that if such action were taken it would be legal.

EVOLUTION OF REGULATION

Common recognition of the evils existing and of the basic causes of the waste obviously taking place by no means indicated common agreement as to the appropriate remedies required. Many recognized that waste stemmed from wide-open production and that in order to achieve conservation it would be necessary to control production in some manner. However, even among those who most ardently supported conservation, bitter controversies arose over the best approach to restriction, whether it should be achieved solely through voluntary cooperative action by the producers, or whether it should be compelled through state or federal action. The growth of the conservation movement, and some of the controversies are reviewed in the interesting book *Antitrust Laws, et. al. v. Unit Operation of Oil or Gas Pools,* written for the A.I.M.E. by Mr. Robert E. Hardwicke as a companion to this volume. The problems and their basic causes are ably summarized in the reports of the Federal Oil Conservation Board, created in 1924 by President Calvin Coolidge.

In spite of the many difficulties, control of production was initiated by the producers in several pools, primarily to prevent surface waste. It soon became evident that the waste that had been occurring underground often exceeded that visible at the surface. The results of research and of technical studies in these controlled pools as well as in uncontrolled pools demonstrated that proper control of production could substantially improve recoveries. Such conclusions were corroborated by the increase in production being obtained through secondary-recovery operations in some semi-depleted pools.

More and more producers began to recognize that it was to their interest to adopt conservation practices, and that cooperative action was needed in order to exploit effectively the rapidly developing technical knowledge. It was apparent, however, that such action was difficult to achieve without some kind of conservation legislation. Furthermore, there were "rugged individualists" who vigorously protested and actively opposed every restrictive proposal. These difficulties led finally to a recognition that the adoption of efficient recovery practices would be greatly facilitated by the enactment of state conservation laws.

There has evolved from this background a system of conservation consisting in the technologic control of production operations. In some areas it has developed primarily through voluntary adoption of improved recovery practices by the producers. However, in most of the important oil-producing states this conservation system now operates through state regulation based on statutes defining and prohibiting waste, and is administered by state agencies through appropriate rules and regulations. The legal history of this development up to 1948 has been thoroughly reviewed in *Legal History of Conservation of Oil and Gas, A Symposium* and *Conservation of Oil and Gas, A Legal History—1948,* published by the Section of Mineral Law, American Bar Association.

Since the major portion of the oil and gas currently produced in the United States comes from states having effective conservation statutes, the conservation system that has finally developed may be considered, for the most part, to be one wherein the police power of the state is exercised to prevent waste. Under this system the rate of production is controlled, and adherence to sound recovery practices is required.

Another function of state regulation that is of slightly less importance than the prevention of physical waste—and indeed is on occasions necessary in order to prevent physical waste—is the recognition and protection of correlative rights of the various producers and royalty holders. Since it is usually necessary to limit production in order to prevent waste, it is important that the allowable production within a field or pool be so distributed among the various operators as to prevent, so far as is practicable, one from obtaining an advantage over another. The allowable production within the state should be so distributed among fields as to treat all concerned with equal consideration. It would be unjust to permit the owners of one field to reap an undue advantage as compared with the owners of another field. Therefore, in states with modern conservation statutes the protection of correlative rights both within fields and among fields is considered to be of great importance, and is based upon the proper and impartial exercise of the state's police power.

The system of conservation that now exists did not spring into being fully developed; it was born with great difficulty. Order did not develop from chaos spontaneously; it was brought about through great effort, often great sacrifice. Its development called for much foresight and wisdom. It exacted change of firmly rooted habits and long-established customs. It demanded the yielding of certain presumed rights and the overcoming of greed. Time, patience, and systematic and continuous effort were required on the part of many people cooperating to reach a common goal. The system is continuing to evolve, to progress, and to change as new technical information is developed, as improved administrative procedures are adopted, and as a better understanding of the requirements is obtained.

The system is not perfect, and there is yet a long way to go before efficient recovery of oil and gas is obtained from every pool. There are still difficulties, some rooted in the past, others because technical developments have proceeded more rapidly than they could become universally understood, appreciated, and adopted. Basic problems still exist that will require the utmost cooperation to overcome. Some oil-producing states have not yet exercised their authority by taking the necessary steps to require the conservation of their petroleum resources. Wide-open production and excessive drilling on small tracts are still occasionally found. Even among those states that take great pride in their conservation achievements, practices vary, and pools are found in which substantial improvement could be made in recovery efficiency.

ACCOMPLISHMENTS UNDER CONSERVATION

In spite of its imperfections, the system of conservation that has been developed has much to its credit. It has made possible an increase of liquid hydrocarbon reserves since 1930 from less than 10 billion barrels, in continuous danger of wasteful dissipation, to over 29 billion barrels of proved and protected reserves at the end of 1950. It has made possible in twenty years an increase in production from an uncertain supply of 2½ million barrels of oil a day to an assured supply of over 6 million barrels a day with a reserve producing capacity estimated to be over 400,000 barrels a day.* Particularly notable was the production increase made

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*Source: Interstate Oil Compact Commission, *Compact Comments* Vol. 6, No. 5, May 1951.

possible during World War II by the backlog of proved reserves and productive capacity in those states where effective conservation was practiced.

The excessively wasteful drilling of wells, the venting of enormous volumes of gas, the uncertain and chronically ailing state of the petroleum industry that characterized the earlier period have been substantially eliminated.

There has grown to maturity in this environment a vigorous, stable, and competitive petroleum industry. In many areas, state regulation, by imposing restraint and providing the rules, did for the individual producers of oil what they, in the absence of rules, were unable to do for themselves. The industry, in turn, was thereby enabled to proceed with the technical developments that have led to more effective exploration, to exploitation of deeper and deeper pools, and to recovery efficiencies previously unobtainable. This mutually complementary relationship has been highly successful. The industry has proved through experience its ability to advance and to improve, and state regulation has proved to be sufficiently flexible to encourage technologic developments.

The public has a great and continuing interest in the preservation and further development of this system of conservation. Its immediately apparent benefits have included not only assurance of a stable supply of petroleum, in which every citizen has a stake, but consumers have been protected through the development of a supply adequate to meet present needs at a moderate price. The oil-producing areas have been specifically benefited in many ways. Stable and attractive communities with schools, libraries, churches, parks, and permanent populations deriving their support directly or indirectly from the steady income provided by oil and gas pools whose capacity to produce is sustained for a generation or more have replaced the boom towns with their shanties erected by the transients formerly attracted to each new oil discovery. Steady tax revenues to both local and state governments have supported public institutions and highways. The permanent employment and stability of income to both private individuals and local governments have permitted long-range planning and the development of a healthful environment in which to develop good citizens.

Relation to Future Supply

It has been shown in Chapter II that the economy of the United States today is very greatly dependent on petroleum. Oil and gas together supply more than half of our total present fuel consumption. Automobiles, aircraft, railroads, ships, industrial consumers, and homes are using oil and gas at a continuously growing rate. It was also shown that the United States is today consuming its oil reserves at a substantially higher rate than the rest of the world. Although our present proved reserves are such as to give no cause for alarm, our continuously growing dependence on petroleum demands that we give serious thought to the future and not confine our attention to past accomplishments.

When viewed with an eye to the future, there stand out in greater prominence among the accomplishments two previously mentioned factors of dominant importance:

1. The development of a vigorous petroleum industry, and
2. Technical advances, which, if properly exploited, can greatly increase the ultimate recovery of oil from existing pools and those to be discovered. On both of these the future supply is dependent.

The petroleum industry, like any other in a free and competitive economy, must be operated along sound business lines to yield a profit. If for any extended period it were unable to do so, the adverse effects would be felt throughout our entire economy. It is important to remember that the continuity of supply and the future supply of petroleum and its products are directly dependent on a sufficient return by the petroleum industry from its operations currently and in the future to maintain and perpetuate itself as a business enterprise.

The soundness of the petroleum industry concerns not the state of a single large enterprise, but the individual health of its thousands of independent component parts. These individual parts are the large and small producers, the integrated and minor oil companies, the independent producers, transporters, refiners, and marketers. The auxiliary, but inactive, participants are the landowners or royalty owners, from whose property the oil and gas are produced. All have a direct and vital concern in the supply of petroleum and, hence, in the soundness of the industry. The fact that all components of the industry have prospered under conservation is what has made the system effective. It has demonstrated that conservation provides both an incentive and a commensurate return.

What may perhaps prove ultimately to be the greatest contribution of regulation is that through orderly development and controlled production an opportunity has been afforded to observe the behavior of oil and gas reservoirs, to determine and analyze the recovery mechanisms, and to develop therefrom new concepts and new standards of efficiency, together with the technical advancement required to apply them to the more complete recovery of oil and gas. During the twenty-odd years of growth of the present conservation system there has taken place a complete revolution in the practices of oil recovery. To a large extent, state regulation has kept pace with this progress. Regulations now considered necessary and commonplace would have been resisted as fantastic as late as the early 1930's, and probably would have been struck down by the courts as constituting an unreasonable interference with the rights of property owners.

In the light of this progress it is now possible to appraise objectively, free from the tensions and emotions of a more chaotic period, not only the accomplishments but, also, from twenty years' experience, the deficiencies and limitations of regulation. The undertaking of such an analysis does not imply that state regulation as an integral part of conservation is outmoded and should now be junked in favor of something new and better. Rather, it is a tribute to a proved and workable approach that has been effective largely because of its flexibility and adaptability to progress. Frank inspection of the specific difficulties and their causes, in order that roadblocks to progress may be removed, is the method that has been relied upon in the past and should be relied upon in the future to stimulate improvement.

OBJECTIVES AND REQUIREMENTS

The immediate objective of the conservation system is to prevent the waste of oil and gas. Subject to the reasonable necessities for the prevention of waste, any regulation should, at the same time, afford each owner a reasonable opportunity to obtain a fair share of the production from a pool.

The first important regulation by the states struck directly at the root of what was then the principal cause of waste—wide-open or unrestricted production. This action immediately raised two questions:

1. How to distribute the total permitted production among the various pools within a state, and
2. How to allocate among the various owners within a pool the total production allowed to that pool.

The intervention of the state removed or at least restricted the freedom of each owner to protect his own property against adverse drainage, and made it necessary for the state to provide new rules or regulations under which, with the changed conditions, the individual owners could recover their oil. Since there was no longer the unrestricted right to drill and produce, some standard of property rights had to be developed, and means had to be devised whereby each owner would still have a fair and equal chance along with others in the same pool to share in the allowed production.

The problem was studied by a number of groups, and in 1931 the Board of Directors of the American Petroleum Institute issued a declaration of policy,* which stated ". . . . that it endorses, and believes the petroleum industry endorses, the principle that each owner of the surface is entitled only to his equitable and ratable share of the recoverable oil and gas energy in the common pool in the proportion which the recoverable reserves underlying his land bear to the recoverable reserves in the pool."

This new concept was somewhat more specifically stated in 1942 by the A.P.I. Special Study Committee on Well Spacing and Allocation of Production in *Standards of Allocation of Oil Production Within Pools and Among Pools* as follows:

> *"The principles governing allocation within a pool are:*
> *a. Physical waste should be prevented.*
> *b. Within reasonable limits each operator should have an opportunity equal to that afforded other operators to recover the equivalent of the amount of recoverable oil underlying his property. The aim should be to prevent reasonably avoidable drainage of oil and gas across property lines that is not offset by counter drainage."*

The conservation statutes of a number of states so provide, in substance, and there are court decisions declaring that such principles are controlling.

The statement of a principle is far easier than its attainment in practice. It would seem that for all practical purposes recognition of the right of each owner to receive under regulation the same opportunity as is afforded all other owners to recover his fair share of the oil and gas in a common pool, coupled with a definition of fair share in terms of the relative amount of recoverable oil underlying each property, would suffice as the basis of a sound and acceptable system of allocation. Unfortunately, the attainment of the indicated end result is sometimes in direct conflict with the steps that must be taken in order to prevent waste. It is in this conflict that the greatest difficulty still lies.

**Section 1, Proceedings of the Twelfth Annual Meeting,* Amer. Petr. Inst. (1930).

Other problems and conflicts also arose when the states began to impose regulations. Administrative procedures had to be developed, and rules and regulations had to be provided governing the drilling, spacing, and manner of completion of wells. Methods of policing had to be established, and forms and records devised. In addition to the problems that were immediately encountered when state regulation was first invoked, each new recovery technique that has since been developed either has brought with it new problems or has aggravated old ones. It is only natural that mistakes were made, but, in the main, successful solutions reasonably satisfactory to all concerned have been found and adopted.

SPECIAL PROBLEMS AND DIFFICULTIES

There still remain some special difficulties, all of which have, in effect, a common root. Their origin is the fact that in any oil or gas pool any withdrawal on any property, or any act that affects the state of the oil and gas under any property, affects the underground conditions and the amount of oil and gas ultimately recoverable from every other property in the same pool. Whether the production be regulated or unregulated, the voluntary, permitted, or required actions of any one producer are his neighbors' concern as well as his own. The administrative complexities of preventing waste through regulation of the acts of individual producers while seeking simultaneously to balance the possible effects, both favorable and adverse, on all other producers are very great.

Oil Migration and Structural Advantage

Before regulation, each owner could attempt to protect himself by drilling offset wells, and closely drilled spots tended to exhaust themselves in a relatively short time. Under regulation, conditions were stabilized, and it was soon recognized that restrictions on drilling and production did not stop the underground migration of oil and gas from one property to another but tended to perpetuate it and even to increase it in some pools. It was quickly perceived that in many instances properties located in certain positions on structure would drain oil from others, and the difficult question arose of whether structural advantage was an advantage inherent in the location of his property that an owner was entitled to exploit over and above his presumed right to recover in proportion to the recoverable oil originally underlying his property.

This difficult question was studied by both the Special Study Committee on Well Spacing and Allocation of Production (API) and its Legal Advisory Committee. On page 46 of their joint report *Standards of Allocation of Oil Production Within Pools and Among Pools,* published in booklet form (1942), appears the following statement:

> *The producing life of a property depends partly upon structural position and its effect on regional migration, especially where there is an active water drive or an expanding gas cap; and this life can be made relatively long or short, and the ultimate recovery can be made high or low, as compared to other properties in the field, by the method of allocation. Clearly, then, structural position must be taken into account because of its effect upon ultimate recovery and drainage. What must be done in any particular field depends upon the conditions in that field. For instance, properties which, because of structural position and regional migration, would not have the opportunity to produce the amount of recoverable oil originally in place if the pool allowable should be based upon relative reserves, should be given higher allowables than the properties which, because of the restriction on the pool allowable, are benefited by regional migration. These last-mentioned properties, in the absence of restriction on the pool allowable, would not, as a rule, be favorably situated; therefore, in most instances, it may be said that,* **if they have a favorable producing position,** *it is* **because of the restriction** *in the allowable of the pool,* **and the method of allocation, not because** *of any inherent advantage existing in nature. The problem is to give high enough allowables to the properties subject to adverse regional drainage so that they will have a reasonable opportunity to recover their recoverable oil without waste, and at the same time not to restrict unduly the properties favored by regional drainage.*

This statement recognizes very clearly the difficulty involved in attempting to devise an allocation formula that will assure each owner an equal opportunity along with other owners to recover in proportion to the recoverable oil and gas underlying his tract. As a practical matter, such a result can almost never be achieved in any reservoir in which the pressure is maintained by either a water drive or a gas-cap drive. Most producers have finally become reconciled to the fact that prevention of waste is the dominant factor and that regulations provided to assure conservation will inevitably cause some properties to gain oil and others to lose through the resultant regional migration. Seldom today is any reasonable allocation formula attacked solely on the basis that it results in some drainage through regional migration.

So long as the owners of tracts being drained are willing to accept the fact that their loss is inevitable where the regional migration is caused through the *natural* response of the reservoir to the imposed restrictions, no conservation issue is involved if the restrictions are adequate to assure efficient recovery. This is often the situation in a pool having an active natural water drive.

The situation is different, however, when restrictions alone are not adequate to bring about efficient recovery. If pressure maintenance can be provided only through injection of gas or water the regional migration that will result is caused not by submission to imposed restraint but by positive action. Under this situation the problem is greatly aggravated. It is no longer a question of preventing waste, but of taking action to increase efficiency. The impossibility of devising any kind of allocation formula that can satisfactorily compensate for regional migration is a real hindrance to the adoption of pressure-maintenance operations that depend on the injection of gas or water.

No practical way of getting around this difficulty is evident except through cooperation among the producers. The difficulty can be completely removed through an agreement for unit operation and distribution of the production. If all interests in a pool are unitized it makes no difference where the oil originates, or through what wells it is produced, for all share in the total production in accordance with their agreement, regardless of migration.

The Problem of Wells

One of the greatest difficulties under state regulation has been the question of what to do about wells. Before regulation, the well was the producing unit. Surface property lines, the size of a tract, and the subsurface conditions beneath it played no part except insofar as they affected the number of wells drilled and their physical ability to produce. If a particular owner had only one well it made no difference whether it was located behind his home on a 50-

foot city lot or in the center of a 20-acre farm. It made no difference whether one thousand barrels or one million barrels of oil originally lay beneath his land. He would recover only what his well produced. Furthermore, each owner could drill as many wells as he saw fit or could afford. The rate at which he could produce depended simply on the aggregate capacity of his wells.

The principle of equal opportunity to recover in proportion to recoverable oil and gas in place was not always recognized, nor were many of the earlier regulations designed in any way to approach it. In several of the states the original objectives of regulatory agencies seemed to be to preserve among the various owners within a pool the same relative participation in the regulated pool production as they had theretofore enjoyed. When production restrictions were first invoked it was very simple to restrict the total production by the direct expedient of restricting the output of each well, either by allowing each well to produce the same amount of oil daily as each other well, or by allowing each well to produce the same fraction of its former production as all other wells. Both of these devices were actually employed in different localities to partition the total allowed production. Allocation to a property was thereby based to a large extent on the number of wells and their potentials rather than on the underlying reserve of oil or gas.

Allocation of production solely in proportion to the number of wells on a property has been called the flat per well allowable. When the potentials of the wells are taken into account the method of allocation has been called an allowable based on potential. "Potential" is the term applied to the productive capacity of a well; it is the number of barrels a well can produce into a tank within some stated interval of time, as, for example, one day or one hour.

Allocation based on these factors failed to alleviate many of the old difficulties, and it brought on new ones, including wasteful practices. Incentive was provided for the drilling of many unnecessary wells, and waste was incurred through the testing of wells at high rates of production to establish high potentials.

It is immediately obvious that under this method of restricting and allocating production only one of the objectives of conservation is achieved. The total production is successfully limited. However, each time a new well is drilled in a pool and receives an allowable all other wells must be permitted to produce less if the total is to be kept constant. Furthermore, the owner who has one well can usually double his production by drilling a second well. Each time a new well is drilled by one owner, owners of adjoining land must drill offset wells to protect themselves against adverse drainage. Unless drilling is rigidly restricted, the result, insofar as drilling is concerned, is much the same as in the complete absence of regulation. Each owner is forced to continue drilling until the point is reached at which it is obvious that a new well will not recover its cost. Excessive and unnecessary drilling are a direct result.

When carried to the extreme this situation leads to a new problem. A point is eventually reached at which the aggregate number of wells becomes so great that the total permitted production is not adequate to yield a satisfactory profit on their operation. Demands then arise for an increase in the total permitted production on the basis that forced abandonment of wells will cause waste through a resultant loss of ultimate recovery. This situation creates a real dilemma. If waste will result from an increase of the total permitted production, but an effective showing has been made that waste will also result from abandonment of wells unless the total is increased, it may be extremely difficult for a regulatory agency to decide which course of action will cause the least waste. If the situation is such that waste will result from either increase of the total permitted production or failure to increase the total, then the primary objective of regulation to prevent waste has not been attained and the regulation has, in effect, been nullified.

It becomes apparent, then, that effective regulation to prevent waste cannot be confined simply to restriction of production. To be effective it must be accompanied by restriction of drilling. Restriction of drilling can take either of two forms:

1. Outright limitation of the right to drill, or
2. Removal of the incentive to drill excessively.

Either of these approaches may be effective, and each has been employed. A combination of the two is often the most satisfactory arrangement.

Limitation of drilling usually takes the form of specification of the minimum acreage on which a well will be permitted. For example, one well on each 10 acres or each 20 acres or each 40 acres may be allowed.

Removal of incentive to drill requires that each owner be permitted to produce an amount of oil that is in no way dependent on the number of wells he owns beyond the minimum required to develop his property. This result is often achieved by allocation of the production of a pool on the basis of producing units or on the basis of unit developed acreage. In New Mexico, for example, a producing unit for an oil well is 40 acres. Each 40 acres is permitted one well and is allowed the same production as each other developed 40-acre tract in the same pool. If, for some reason, the drilling tract comprises more than or less than 40 acres, the unit allowable for such well is increased or decreased in the proportion that the number of acres in the drilling tract bears to 40, minor fractions of an acre being disregarded. Allocation by this method is commonly referred to as being based on 100% acreage. It is often employed as a simple and practical, even though only approximate, index to the relative amounts of recoverable oil or gas underlying various properties within a common pool. It is obvious that with allocation based in this manner on the developed acreage rather than on the number of wells, an owner would have no incentive to drill a second well on a 40-acre producing unit, even if he were permitted to do so, because the second well would not increase his permitted production.

Allocation on the basis of developed acreage has been very effective in curbing excessive drilling of the sort normally encountered. The same result is accomplished when each well obtains the same allowable as all other wells but drilling of more than one well on a tract of specified size is strictly prohibited and no exceptions are allowed. The weakness of the latter approach is the temptation it offers for special exceptions and its vulnerability when small tracts are involved.

The Special Problem of the Small Tract

Difficulty with any system of allocation almost always arises when a pool underlies a number of separately owned small tracts. If the owner of a tract does not have a well, and thereby a means of participating in the total production from a pool, the oil and gas underlying his tract will drain to others just as surely under a regulated system as if production were not regulated. He must be given the opportunity to recover his share of the oil and gas within the pool. If his tract is smaller than the established minimum size for a well, and he is denied the right to drill, he is directly deprived of his property.

Offhand, it would seem fair and reasonable when confronted with this situation to permit an exception to the usual spacing pattern in order that the owner of the small tract might recover his oil. The solution, however, is not so simple. As soon as the well has been drilled the problem arises as to how much it should be allowed to produce. If the allocation system in effect for the particular pool is that each well receives the same allowable, the new well automatically receives the same production as all other wells. The effect is that the new well begins to drain not only the owner's small tract but all adjoining tracts. Owners of adjacent tracts are forced to demand that they be permitted to drill additional wells to protect their properties against adverse drainage. If additional exceptions are granted similar discrepancies in participation spread throughout the pool until the whole basis of the drilling restrictions is destroyed. Exceptions to the normal spacing pattern from this cause alone resulted directly in the drilling of over 13,000 wells in the East Texas field that were in no way needed to recover the oil from the pool as a whole.

A different but equally difficult problem exists if the well on the small tract is permitted to produce, not at the same rate as all other wells, but only in proportion to the relative acreage of the small tract or at a rate just sufficient to prevent drainage from the tract by others. The tract may be so small that the oil recoverable from beneath it may not be sufficient to return the cost of a well; or the permitted production if the well is allowed to produce only in proportion to the acreage of the tract may be too low even to pay the operating costs of maintaining the well on production. This situation is often encountered when all or part of an oil pool lies beneath a townsite or other area that is divided into very small tracts. For example, if a pool containing a recoverable oil reserve of 10,000 barrels an acre is developed on a pattern of one well to each 20 acres, and each well is permitted to produce 40 barrels daily, or 2 barrels daily for each tributary acre, a 50-foot by 100-foot town lot would have beneath it only 1,150 barrels of recoverable oil, and a well on such a lot could be allowed only ¼ barrel a day if it were permitted to produce only in proportion to the acreage of the tract.

Restrictions alone are not capable of dealing with this situation, for there is no solution that can be satisfactory to all concerned on the basis of ordinary fairness. If the town lot in the example cited is denied a well the owner loses 1,150 barrels of oil to which he is entitled. He cannot afford to drill a well to recover 1,150 barrels; a permit to drill accompanied by a permitted allowable of ¼ barrel of oil a day is just as effective in preventing drilling as is denial of a permit. If drilling is permitted and the well is then allowed to produce at a rate that will allow the profits from the operation to retire the cost of the well plus the 1,150 barrels it was originally drilled to obtain, the result might be considered fair by the owner of the town lot, but every bit of production obtained in retiring the cost of the well would have to be drained from other owners in the same pool. In effect, the other owners would have to pay for the cost of the well and its upkeep. If the well were actually permitted to produce at the same rate as all other wells it would eventually produce a total of 200,000 barrels, all but 1,150 of which would be involuntarily contributed by other owners. It is inconceivable that they would consider it fair to relinquish 200,000 barrels of oil for the ostensible objective of allowing the owner of a town lot to recover his own 1,150 barrels.

This situation has but one real solution. If the objective is to give the town-lot owner a fair opportunity to recover his own oil, but no more, it is obvious that the small tract must be pooled with other small tracts until their aggregate acreage is sufficient to meet the established minimum for a well, or means must be provided whereby the small tract can, without a well, participate equitably in the total pool outlet through pooling with larger tracts, or unitization. Both of these methods have been employed effectively.

If the pooling is voluntary no question is raised, and the result is considered fair by all. If compulsion is attempted, as, for example, by denial of a permit to drill except on pooled tracts aggregating sufficient size to be allowed a well, vociferous protests are often raised by those who look upon the ownership of a small tract as an inviolable right to drill and to produce profitably through drainage from their neighbors. During World War II the pooling of small tracts for drilling was compelled by the Petroleum Administration for War. Such pooling is also compulsory in several states, at least to the extent that a permit to drill is given to the owner of one tract in a unit and the owners of other tracts are permitted to participate in the production. Some of the oil-producing states have been reluctant to compel pooling, and many unnecessary wells have been drilled as a result of town-lot drilling.

The problem of small tracts has been analyzed so far only in relation to drainage from one property to another. There would be no conservation question if that were the sole consideration. Conservation is involved, however, in several very important ways:

1. To the extent that wells drilled on small tracts and additional wells drilled on adjoining tracts for the sole purpose of reducing

adverse drainage are not required for the efficient recovery of oil or gas from a pool, they constitute excessive drilling. Excessive drilling increases both development and operating expenses, and adds to the cost of oil and gas. The additional cost may be a direct cause of reduced ultimate recovery through dissipation of capital that might otherwise have been available for other facilities for increasing recovery, and through causing the economic limit of the operation to be reached at an earlier stage of depletion. Both steel and labor are wasted. None of these is in the public interest.

2. To the extent that excessive drilling on small tracts causes an excessive localization of withdrawals, underground waste may result directly from the resultant disturbance to the proper control of gas and water as displacement agents. This is avoidable waste, which the states have the authority to prevent.

3. To the extent that wells drilled throughout a pool to reduce adverse drainage to small tracts may constitute too great a total number to be supported profitably when the pool outlet is restricted to an efficient rate, waste may be caused by the resultant demand for higher total allowable.

Excessive Drilling With Uniform Spacing

The fundamental question might well be raised as to why the permitted production from a property should be dependent in any way on the number of wells. The answer to this question seems to lie in the fact that a property cannot produce oil without a well, unless it is pooled, and a regulatory agency charged with the responsibility of regulating production and allocating it among the properties has to have some yardstick by which to be guided. An owner cannot be compelled to drill and develop his property; he can be afforded the opportunity to do so. He has the right to refrain, but, if he refrains, his failure to drill cannot deprive others of their right to develop their properties and to produce.

If the intent of the allocation method employed is to afford each owner a reasonable opportunity to produce the recoverable oil beneath his land it seems reasonable to presume that the owner is exercising that opportunity when he drills wells to develop that land, but is refraining when he fails to develop. It has become customary, therefore, to assign allowables to existing wells without credit for "undrilled" acreage.

The practice has been for the state to set the well-spacing patterns and thereby to decide what constitutes development. For example, the established development may be set on the basis of one well to a specified area, such as 10 or 20 or 40 acres. Whatever the basis, and regardless of the total number of wells on a property, no credit is given for the acreage within the property not specifically assignable to a well on the established pattern or unit.

One difficulty with this approach has been that often the spacing pattern in a pool is set soon after discovery and before it is known what will prove ultimately to be the proper recovery method. If the number of wells required by the pattern proves ultimately to be too few the situation can always be corrected by the later drilling of additional wells. Too often, however, the reverse is true, and more wells are drilled than will ultimately be required. The excess wells burden the operation with increased investment and increased operating costs, both tending to affect ultimate recovery adversely.

Great advances have been made by the states in reducing the unnecessary drilling that results from the establishment of spacing patterns smaller than necessary. There is still room for improvement, however. If the situation in the future is to continue to be one in which each individual property must have wells situated on it in order to obtain a share of the production, a proper ultimate solution would seem to lie in the direction of setting, first, a *development* pattern requiring the drilling of the minimum number of wells required to outline the productive limits and to determine adequately the character and degree of continuity of the productive reservoir, and, second, a *production* pattern calling for the minimum number of wells required to recover the oil efficiently by whatever method appears best to meet the needs of the specific pool. The required number of wells could be based on the total maximum efficient producing rate for the pool as a whole and the maximum rate at which a well could be produced without waste, each determined on the basis of factual evidence. Such an approach could undoubtedly reduce the number of unnecessary wells now drilled because of arbitrary spacing patterns.

In the final analysis, however, it must be considered that any well not actually needed to obtain reservoir information or to recover the oil efficiently is an unnecessary well. Conservation would be promoted if all non-essential wells could be dispensed with and producers could be relieved of their burden. The saving would also benefit the ultimate consumer. It has been shown in prior chapters that maximum ultimate recovery of oil is not dependent on there being wells on each property, but is dependent on the operation of an entire reservoir with a single, efficient recovery method, with the wells so situated with regard to the structure and geology of the reservoir as to bring about the most effective displacement of the oil. The requirement of wells on each property is therefore an artificial rather than a natural requirement, and is brought about through the fact that it is only through having wells on his property that an owner can obtain a share of the production. This situation suggests that the most effective way in which to eliminate the drilling of unnecessary wells would be for the owners of separate tracts within a reservoir to pool their properties into a single whole. Thereby the entire reservoir might be operated for maximum recovery, with wells properly located to promote efficiency, and with each owner receiving a share of the total production. Such an arrangement is best achieved through unit operation.

Pools With Gas Overlying Oil

Another very difficult situation arises in the conflict between the requirements for waste prevention and the individual interests of landowners in pools where extensive gas reserves overlie oil in a common reservoir. The conflict is particularly aggravated when some properties are underlain by gas only.

It has been shown that in a reservoir of this type it is essential to prevention of underground waste to retain the free gas in the reservoir. This is required regardless of whether the reservoir is to be operated by gas-cap drive or by water drive. If gas-cap drive is to be employed, all of the gas must be retained within the reservoir to maintain pressure and to displace the oil. If water drive is to be employed, shrinkage of the gas cap cannot be tolerated. Depending upon the degree of reservoir pressure decline required to bring about the water influx, a limited expansion of the gas cap can take place, and a correspondingly limited production of free gas may be permitted, but the total gas production cannot be allowed to exceed the net expansion of the gas cap. This is usually a very severe limitation; it is most severe when the reservoir pressure is maintained at a very high level.

It is obvious that conservation requires that the owners of gas wells in an oil reservoir be restrained from producing the gas underlying their land. Depending upon the mechanism employed to recover the oil, this restraint may have to take the form of complete prohibition of production of free gas. Since the purpose of the restraint is to cause the reservoir supply of gas to be used either directly or indirectly to increase the recovery of oil, the effect is to utilize the property of gas owners for the benefit of those who own the land underlain by oil.

If gas-cap drive is employed in a reservoir, prohibition of free-gas production does not merely cause owners of gas wells to defer production of gas until a later date. The gas cap encroaches into the oil zone to displace the oil, and the gas underlying one property flows underground to the property of another. Restriction of gas production may thus be said to result in the transfer of the property of one owner to another.

If outright prohibition of the production of gas wells in oil reservoirs is imposed, the owners of land underlain only by gas are placed in a very difficult position. They can receive no current income from their property until the oil recovery operation is completed, and at that time they may have no gas, for it may all have migrated to other properties and may eventually have become completely dissipated in the oil recovery operation. The lessee of a tract containing only gas wells may be unable to retain his lease, for the usual lease contract expires unless oil or gas is produced.

The owner of a very large gas-bearing area may sometimes protect himself to some degree in this situation if the gas is rich enough in condensable hydrocarbons to support a profitable cycling operation. By stripping the heavier hydrocarbons and returning the dry residue gas to the gas cap he may obtain currently some revenue from his property. Cycling is sometimes carried on in the gas cap of an oil reservoir, but often the reservoir conditions or the composition of the gas are such that cycling is not feasible. Even if cycling is employed, the owner is still denied an opportunity to recover his dry gas, except possibly at some future time, and he may eventually lose all or a great part of it through subsurface migration.

It would seem in this situation, if the property of one owner is to be used for the exclusive benefit of others, that it would be fair and reasonable for the first owner to be compensated in some manner for the use of his property. This solution, however, is not one that can be provided solely through regulation and control. The effect of severe restriction or prohibition of gas production is to dedicate the use of the gas in the reservoir for the common good. That one owner loses and another gains is not an objective but simply an inevitable result. No state regulatory agency has attempted in this situation to place a value on unproduced gas and to compel oil producers to compensate owners of closed-in gas wells.

The usual situation is that the owner of a gas well is permitted to produce gas in spite of the fact that such production of gas may cause loss of ultimate oil recovery. Thus, the inequities that would result from rigid imposition of restrictions designed to prevent waste act in part to nullify the waste-prevention measures.

It appears that the inequities of this situation could best be relieved through supplementing the imposed regulations by cooperation among the various producers. Unit operation, perhaps on a voluntary basis, offers a means by which the producers, including owners of gas wells as well as oil wells, might bring about an equitable distribution of the total production while at the same time retaining the gas in the reservoir to increase the efficiency of the oil recovery.

CONDENSATE RESERVOIRS

No particularly difficult problems of regulation of gas reservoirs arise that are peculiar to gas, except in condensate reservoirs. The problem of gas migration from one part of the reservoir to another if pressure is maintained by water drive, and the problems of whether or not to permit wells on small tracts and how to distribute the permitted gas production among the various owners are similar in most respects to the same problems in an oil reservoir. It is generally recognized that gas will migrate over great distances and that the amount of gas recoverable from a small tract will be insufficient to pay for a well. It is therefore becoming a commonly accepted practice in gas fields to pool small tracts until enough acreage is provided to support a well.

Very little waste takes place in most dry gas reservoirs, for, outside of the costs sometimes incurred by the drilling of unnecessary wells, the disturbances to ownership rights that may result from migration of gas from one property to another are usually not such as can in any manner cause underground waste. Surface waste through flaring of gas from gas wells almost never occurs unless the gas has first been used in some manner to lift oil. Purchasers of gas are in general forced to take gas ratably from the various properties in a common pool.

A special problem arises, however, in those gas pools in which the condensate content of the gas is such that decline of reservoir pressure would cause loss through condensation of liquids within the reservoir, and in which the physical characteristics of the reservoir and the size of the reserve are such that cycling would be a feasible and efficient method for recovery of the condensate.

It is essential to efficient recovery of condensate by a cycling operation that the entire gas reservoir be operated as a single entity. It is impossible to carry on cycling with a single well; in order to obtain efficient recovery the injection wells and production wells must be so located as to cause dry gas to sweep as much as possible of the entire area of a reservoir. Efficient displacement of the wet gas cannot be obtained by well patterns such that both production wells and injection wells are located on each individual property. Furthermore, cycling on some properties for the purpose of maintaining reservoir pressure and effecting efficient recovery of condensate would be fruitless if other properties in the same reservoir were permitted to reduce the reservoir pressure by withdrawal of gas. Not only would the reservoir pressure be reduced on those properties where cycling was being carried on, nullifying the effects, but gas would drain from the cycled properties to those simply producing gas.

If cycling were taking place in a reservoir any property located between an injection well and a producing well, while not drained of gas, would nevertheless have its wet gas replaced by dry gas, and would thus be drained of its condensate.

All of these facts are well known and commonly understood by both producers and state regulatory agencies. It is also universally recognized that cycling of a gas reservoir cannot be achieved merely by regulation but is possible only through participation among all owners within a pool. Accordingly, it is now common practice to carry on cycling operations through unit-operation programs in which all interests share the recovery.

DEFICIENCIES OF REGULATION AND NEED OF SUPPLEMENTAL APPROACH

Regulation has achieved most of its objectives and, taken as a whole, has been highly satisfactory. It still has some weak spots. Chief among them are: excessive drilling has largely been reduced but has not been eliminated, particularly where small tracts are involved; it has not been possible to allocate production in all pools on a basis that will always meet ordinary standards of fairness; and it has become apparent that restrictions alone cannot always cause an oil reservoir to be operated efficiently.

For the purpose of analyzing the principal weaknesses, it might be considered that there are three broad classes of oil and gas pools, as follows:

1. Those pools in which uniform spacing of wells, control of production rate, and prohibition of excessive production of gas or water are entirely adequate to assure efficient recovery through the natural response of the reservoir to proper operating controls and without serious damage to the rights of individual owners. In pools of this type there is room for substantial improvement in the reduction of unnecessary drilling and in more equitable allocation. These are pools, however, in which it is not likely that, with the present state of technical knowledge, additional recovery could be obtained through a different type of operation. Most dry gas pools and many oil reservoirs having adequate natural water drive are in this category.

2. Those pools in which regulation could be adequate to assure efficient recovery, but in which rigid imposition of the required restrictions would so disturb accepted property rights that the practical effect is either failure to invoke completely the required degree of regulation, or the effect of the regulation is in some manner nullified. Many pools with large reserves of gas overlying oil are in this category.

3. Those pools in which control of production rate, limitations on drilling, and control of the production of gas and water will not suffice to insure efficient recovery. Oil pools suitable for and requiring artificial gas-cap drive or edge-water drive, and condensate reservoirs suitable for and requiring cycling, are in this category. For each of these recovery methods it is essential that an entire reservoir be operated as a single producing unit. There is no other practical way in which to obtain efficient recovery.

Analysis shows that the deficiencies and limitations of regulation all arise from the conflict between individual property rights and the physical requirements of efficient oil and gas recovery. Regulations limited to permission, restriction, and prohibition of the individual acts of individual owners are adequate in certain pools in which compliance does not so greatly conflict with individual property rights that the regulations are circumvented or their effectiveness nullified by the steps taken by individual owners to prevent confiscation of their property.

Cooperation Needed to Resolve Conflicts

In many pools protection of property rights and efficient recovery are so irreconcilable that regulation alone is completely inadequate. In such pools it is essential that regulation be supplemented by an auxiliary approach. Over and above any regulations that may be provided to prevent waste, cooperation among all owners must be secured in such fashion and to such degree as will remove the conflict between protection of property rights and the requirements of waste prevention, and as will result in the production of each pool as a single natural reservoir unit with the single dominant recovery mechanism best designed to effect the most efficient ultimate recovery.

Such a result can be obtained if the property rights of the individual owners are pooled and the right of each owner to develop and produce his own property independently is exchanged for a proportionate interest in the total production of an entire pool. By removal of the conflicting interests of the owners the way is opened for their joint participation in a common operation best designed to meet all requirements for efficient recovery.

Unit Operation Offers Feasible Solution

The question naturally arises as to what is or should be the attitude of the state, and to what extent the state may or should restrict or promote cooperative exploitation of petroleum reservoirs. Our state governments have the power to prevent physical waste and to protect correlative rights. Under this power, they find it necessary to prevent waste in the form of excessive production of gas or water, and to restrict oil production from individual properties. Under the rights guaranteed by our constitution, landowners and producers cannot be deprived of their property without due process of law. Restriction of oil production in any form, direct or indirect, inevitably changes the relative participation of every oil producer in a common pool. Under capricious administration one owner's property may be handed to another, and even under the most careful administration such transfer of property may, to some degree, be inevitable.

The objective of a state administrative agency that allocates production or controls the spacing of oil wells under waste-prevention statutes is, first, to prevent waste, a clearly defined power of the state, and, second, to attempt, insofar as is reasonably possible and compatible with the prevention of waste, to give each owner or producer a reasonable opportunity to receive or recover a fair share of the oil and gas within the common pool. The difficulty is that these two administrative requirements are in many cases directly contradictory to a varying degree. Prevention of waste through control of the production of gas and water, or restriction of oil production, or prevention of waste through the use of pressure maintenance operations involving injection of gas or water may be a direct cause of migration of oil or gas from one property to another. In many cases no conceivable allocation formula can give to the owner of an adversely located property any chance to recover the equivalent of the oil underlying his property if all the wells in a pool are permitted to produce at reasonable rates.

One manner in which the owner of a property with an unfavorable location can recover the equivalent of his oil is for him to receive a share of the oil produced from the leases to which his oil is forced to migrate. Title to this oil produced on other leases rests, however, with the producers and not with the original owner from whose property the oil migrated, unless a different arrangement results from agreement. To promote conservation the state should permit and encourage the various producers in a pool to agree upon a fair and equitable division of the pool's production in order that they might, through joint operation, prevent underground waste and increase ultimate recovery. There is nothing in such a program that is anti-social or contrary to public policy in any respect. Such an agreement is not a device for effecting restraint of trade but provides a framework within which separate owners may receive and enjoy their properties under a system where restraint is imposed to prevent physical waste. The agreement is thus an arrangement that permits the state to exercise its police power to prevent waste without depriving of their property those who are affected.

Some have the notion that a unit-operation agreement or unitization takes unfairly from one and gives to another, and that it discriminates against the small landowner or lease owner in favor of the holder of large tracts. It is essential that it be clearly recognized that unit operation is not something that deprives an owner of his property or his right to its enjoyment, but is rather a device of convenience that he himself may employ through agreement with others for the express purpose of independently safeguarding his property. The pooling of ownership rights does not in itself directly increase recovery or prevent waste, but it makes possible the development and exploitation of a pool to yield the maximum ultimate recovery, by making it possible for all operators to participate in the venture, those whose properties will be drained as well as those whose properties will benefit by the forced migration essential to efficient recovery.

Unit operation or unitization is not a novel idea. It was seriously proposed and considered long before state regulation became effective. It was ardently championed by Henry L. Doherty as early as 1924. The advantages of unit operation were heavily stressed in the reports of the Federal Oil Conservation Board, in the reports of various committees that studied the problems besetting the petroleum industry during the period of wide-open production, and in many technical papers before 1931. Practically every individual or group who studied the problems of waste of oil and gas and its causes recognized the necessity of cooperative action to secure efficient recovery. The disagreements revolved primarily about the methods required to bring about cooperative action rather than the principle.

In hindsight, it now seems fairly evident why unitization was not widely adopted. The chief problems causing waste of oil and gas and keeping the petroleum industry in a chronic unhealthy state prior to the development of the present system of conservation were unrestricted drilling and wide-open production. These were by far the most direct causes and the most important causes of waste. It was also generally believed at that time that if production were restricted and the gas associated with crude oil in the reservoir were conserved, efficient recovery would be assured. Many of those who proposed cooperative action were thinking in terms of restrictions on drilling, on well density, and on production rate through cooperative action and agreement. When the various states adopted conservation statutes and began to regulate drilling and production it appeared that state regulation would provide substantially all of the benefits previously expected through cooperative action. Interest in unitization lagged while the administrative, legal, and technical talents of the industry were devoted to the task of trying to solve the problems associated with state regulation. These expectations were reasonable in the light of the technical knowledge available during that period and have been borne out by the tremendous advances since made.

It is becoming increasingly apparent now, however, that in many oil and gas pools unit operation should be reexplored as a supplement to the present system of conservation. The reasons now existing for unit operation are not the same as those most strongly urged before. It is not required to prevent the frenzied drilling of wells, the wide-open production of oil, the blowing of gas to the atmosphere, and the immediate dissipation of each new oil reserve soon after discovery. All of these have been fairly well taken care of. Cooperative action and unit operation are needed now, not to prevent obvious waste, not to act as a brake on drilling and production, but to protect property rights, to preserve individual enterprise, and to permit the effective implementation of advances in technical knowledge, to the end that positive steps may be taken in each pool to bring about a higher extraction efficiency.

Chapter X

COOPERATIVE DEVELOPMENT AND UNIT OPERATION

THE NEED OF COOPERATIVE ACTION

It has long been evident that conservation of oil and gas is not possible through purely individual action on the part of each owner; it is also becoming increasingly apparent that completely effective conservation cannot always be achieved through regulation alone. In either case, the same basic difficulties arise from the migratory nature of oil and gas and the conflict that results between individual property rights and the physical requirements of efficient recovery of oil and gas.

The characteristics of oil and gas reservoirs were set by nature eons ago, possibly before man existed—certainly before he became aware of petroleum or had a need for it. Those natural characteristics are fixed and unyielding; they do not readily adapt themselves to modern concepts of ownership or value. Modern though they may be in comparison, individual property rights were acquired through generations of struggle, and they also are tenaciously held and jealously guarded. The essence of the conflict that arises from these considerations may be recapitulated briefly as follows:

1. A landowner has the right, subject to reasonable regulation by governmental authority, to exploit the oil and gas underlying his land.
2. The owner of a well is recognized as the owner of the oil and gas that reach the surface through his well. The oil produced from his well may or may not have been beneath his own property when the well was put on production. His well may drain other properties, or his own land may be drained by others.
3. To protect his property, a landowner must have a well or wells located on that property, and he must, by exercise of due diligence, assure himself of an opportunity at least equivalent to that of other property owners to reduce to physical possession aboveground his proportionate share of all oil produced. Thus, each parcel of land must have a well or wells on it, and must be independently

exploited, unless some alternative method of securing a share of the production be arranged.

4. The nature of petroleum reservoirs is such that maximum recovery of oil or gas is not necessarily obtained by production from wells located on each parcel or tract of land. If efficient recovery is to be obtained, oil and gas must be forced to migrate. The direction and degree of migration required for efficiency in any particular reservoir are dictated by the specific physical structure and by the recovery process. They can in no way be controlled arbitrarily by surface property boundaries. Property rights are always affected, some favorably, some adversely. Pressure maintenance, gas-cap drive, water drive, cycling cannot be carried on effectively except in large areas or whole reservoirs; for each of them wells must be located with respect to the characteristics of the reservoir rather than with reference to property lines. Thus, in many pools efficient conservation practices may require that oil or gas be deliberately forced to migrate from one property to another, and that the opportunity of certain properties to produce oil or gas through wells located thereon be greatly restricted or even denied entirely.

The obvious remedy, and what is perhaps in many cases the only satisfactory remedy, for this situation is for the property owners to agree on the method of exploitation of a reservoir to obtain the maximum ultimate recovery, and to remove the conflict by agreeing to apportion the total recovery upon some fair and mutually satisfactory basis.

THE PURPOSES OF COOPERATIVE DEVELOPMENT

The fundamental purpose of cooperative exploitation of oil and gas pools is to carry out or make possible the carrying out of recovery procedures designed to increase the ultimate recovery of oil and gas from an entire reservoir, which procedures either could not be carried out individually, or, if carried out individually, would disturb the ownership rights in the common pool. For example, through cooperation the owners in a common pool may carry on artificial pressure maintenance or secondary recovery through injection of gas or water, or a cycling operation for condensate recovery, or control the use of a gas cap to maintain the pressure of an oil reservoir, each for the purpose of increasing the ultimate recovery. These actions may be purely voluntary, the incentive being the greater return to be obtained through efficient recovery.

On the other hand, if the state, for the purpose of preventing waste, compels restriction of production rate, regulates the spacing of wells, prohibits or restricts the production of gas, or compels the return of produced gas or water to a reservoir for the maintenance of pressure, the various owners may resort to cooperation, with an agreement as to distribution of the production, as a means of protecting their property rights and effecting certain economies that will make it practical and feasible for them to operate under the imposed restrictions.

THE KINDS OF COOPERATION

Although integration of all separate interests in a pool is often the most effective and sometimes the only practical way by which to bring about operation of an entire reservoir in the manner best designed to obtain efficient recovery, various other cooperative procedures are also employed to promote efficiency. Different types and degrees of cooperation are required and are practiced in different situations. They vary all the way from a simple exchange of technical information to complete integration of properties.

Exchange of Technical Information

It has been shown in earlier chapters that efficient recovery requires that a great deal of factual information be available with respect to a reservoir. The geologic conditions, the thickness, continuity, texture, permeability, porosity, and the water, oil, and gas content of the producing formation, and their variations throughout the reservoir; the characteristics of the reservoir oil and gas; such operating data as subsurface pressures and oil, gas, and water production of individual wells—all must be known for an entire reservoir in order to determine the recovery mechanism operating, the efficiency being obtained, and the proper controls necessary for increased recovery. Each owner has access only to his own property; he cannot individually determine the required information for an entire reservoir. Thus, the basic facts required for intelligent operation and for proper reservoir control can be accumulated only through cooperative action or exchange of information among the various individual producers.

These data are often gathered and exchanged through committees representing the various operators. In other cases the information is exchanged individually.

Under some conditions injection of gas or water is carried out according to a plan whereby each operator carries out his own injection and regulates the injected volumes in accordance with an agreed coordinated program. Certain facilities may be shared or traded, as, for example, by location of injection wells on lease boundaries. The individual properties are operated separately. No interests are traded, and property rights are not affected. Migration across property lines is avoided, or is balanced and equalized, by careful control of the relative volumes injected and produced, in accordance with the agreed plan.

This type of cooperative production is suitable only for those reservoirs that are adaptable to pattern injection. It is not applicable to artificial edge-water drive or to artificial gas-cap drive.

Where a natural water drive or a natural gas-cap drive is already operative and the relative participation of various properties in the allowed production is already fixed by an accepted allocation formula imposed by state regulation, cooperative injection of produced gas or water and cooperative action to prevent their dissipation are sometimes carried on where the situation is such that these can be done without any new disturbance to property rights over and above that already taking place as a result of the natural reaction of the reservoir to such control as is forced by state regulation to prevent waste. For example, in many pools having natural water drive the produced water is returned to the producing formation to assist in maintaining the reservoir pressure. The injection may be carried out individually or through shared facilities.

A novel arrangement for preventing or reducing excessive production of water or gas is the transfer of allowables from one property to another. For example, in the East Texas field a well that is producing a large quantity of water may be closed in to conserve the reservoir supply of water, and the owner, with the approval of the state administrative agency, is permitted to arrange with the owner of another well elsewhere in the field to produce for him the allowable of the closed-in well. A somewhat similar practice is followed in certain reservoirs of the Stratton field in south Texas. There the oil is produced by a gas-cap drive, but extensive areas of the reservoir contain only gas. A gas well is given an allowable based on its acreage and on the withdrawal of reservoir volume allowed an oil well. This gas allowable is converted to an oil equivalent based on the prices of gas and oil. In order to avoid the withdrawal of gas from the gas cap, the oil equivalent of a gas-well allowable may be transferred to the owner of an oil well elsewhere in the same reservoir.

Transfers of the sort practiced in East Texas and in Stratton are sanctioned by the state regulatory commission in written orders, but the actual carrying out of the transfers is purely voluntary and is arranged privately by the producers involved. Such transfers are feasible only where they do not disturb property rights.

Joint Ownership of Facilities

Still another form of cooperation is through the joint ownership or use of facilities which operators acting individually might be unable to afford or which can be shared more efficiently than they can be duplicated.

Examples are gathering systems for the collection of produced gas or water, water-disposal facilities, injection wells, compression plants for return of produced gas to a reservoir for pressure maintenance, and facilities for processing of produced gas for recovery of natural gasoline or condensate and preparation of the gas for storage, for marketing, or for return to the reservoir. Such facilities may be jointly owned, or they may be owned by one operator but used by all through some manner of payment.

Jointly owned facilities may be employed whether the producing operations are carried on separately or are completely integrated.

Integration of Ownership

In many situations complete integration of ownership, or a similar arrangement, is the only feasible means of accomplishing the objectives.

Pooling

The integration of separately owned tracts within a drilling or development unit so that the area may be treated as a single unit is commonly called "pooling." Pooling usually relates to the combining of small or irregularly shaped tracts for the purpose of providing a well or a production unit. For example, the owners of a number of small contiguous tracts may pool their properties for the purpose of providing a 40-acre drilling unit for an oil well or a 640-acre drilling unit for a gas well, or a small tract may be pooled with an adjacent larger tract in order to become a part of a drilling unit.

Unitization and Unit Operation

The practice of unifying the ownership and control of a large area or an entire oil or gas pool by the issuance or assignment of units or undivided interests in the entire area with provision for development and operation by an agent, trustee, or committee representing all holders of undivided interests therein is usually called "unitization."

The terms "unitization" and "unit operation" are frequently used synonomously; however, distinction between them is sometimes made on the basis that the term "unitization" involves cross assignments of interests, whereas "unit operation" refers to joint development and operation of the unit which is formed, with or without cross assignments.

The specific intent is to combine separately owned tracts in such manner that they may be developed and operated as if they were a single property, instead of separately. The procedures employed to accomplish this result vary. Whatever the legal procedures employed, the result is that the owner of an individual tract trades his right to develop and produce that tract for a share in the production from the entire unit.

UNIT OPERATION

Unit operation frees the operation of a pool of those restrictions that might otherwise be imposed by the conflicting interests of the individual owners. Under unit operation there is no conflict of interests, but, instead, a joint and common interest in carrying out the operation as efficiently and economically as possible for the maximum recovery.

Formation of a Unit

A unit is formed through negotiation among the individual owners. There must be a common reason or incentive, a joint purpose. Agreements must be worked out that will determine the share of each owner and what his obligations will be. Agreement must be reached on how the unit operation will be carried on and by what procedure it may be modified.

The understandings reached in forming a unit are ordinarily reduced to writing, and often they are recorded. One document or several may be employed for this purpose. The documents are important, for they may govern the operations over the remaining life of the pool. They should cover as thoroughly as is possible without becoming excessively burdensome and complex, all phases of the operating, legal, and accounting features of the project, as well as all future contingencies.

The essential steps involved in the formation of a unit are usually as follows:

1. Recognition by one or more producers in a particular pool that unit operation is necessary in order to obtain efficient recovery.
2. Acquisition of the geologic, engineering, and operating data required for a thorough analysis of the reservoir behavior and a determination of the proper method of operation.
3. Appraisal by all producers in the pool of the probable total benefits to be obtained through the proposed unit operation, and agreement in principle on its adoption.
4. Negotiation and agreement on the basis of participation.
5. Decision on the type of operation to be carried on and the details of the operating, accounting, and business arrangements.
6. Execution of agreements and appointment of all necessary committees.
7. Obtaining the consent of royalty owners.
8. Obtaining the sanction or approval of the agency responsible for regulation of oil and gas production in the area involved, as may be required.

Although unit operation may be proposed at first by a single producer, the formation of a unit is from start to finish a cooperative procedure. At nearly all stages committees representing the various producers develop the basic information required, and meetings are held for discussion of all aspects. All operating interests are usually represented in the committees that direct the operation after a unit is formed.

The agreement is sometimes confined to the "working" or operating interests, but complete integration of all royalty interests as well is highly desirable and is often necessary for effective unit operation. In any event, it is essential that the royalty owners be advised of and understand the purposes of the unit operation, the type of recovery method to be carried on, why unit operation is necessary, and its effect on their interests. In unit operation, as in all cooperative ventures, harmonious and satisfactory relationships are best developed through mutual understanding.

Since the individual owner who participates in a unit exchanges his right to develop his property independently for an equivalent right in the community development, he can afford to participate only if he receives a percentage of the whole that he considers a fair and equitable trade for his contribution to the whole. The most important negotiation leading to unit operation is therefore that involved in reaching agreement on the basis of participation.

This negotiation requires two steps, as follows:

First, agreement must be obtained as to what will constitute the basis or measure of each participant's share, and

Second, after agreement on the basis, each property must be specifically evaluated on that basis to establish its percentage of the whole.

The bases most commonly employed for determination of the percentage participation in a unit are

1. The productive acreage.
2. The amount of oil or gas in place.
3. The amount of recoverable oil or gas in place.
4. The value of the oil and gas in place.

Acreage

A pool is sometimes unitized either prior to development or so early during the development that nothing at all or very little is known regarding the prospective volume of oil or gas underlying each individual property. Under such circumstances the owners are frequently able to agree on the use of productive acreage alone as a fair and reasonable measure of their relative rights. Their respective productive acreage can then be determined later as the limits of the pool become outlined during development.

Participation on the basis of acreage is also sometimes employed in a developed pool where the geologic information required to determine the amount of oil or gas underlying each property is not available in adequate detail for specific evaluation of each on any other basis, or where the productive thickness does not vary greatly throughout the pool. Acreage alone is often the basis employed in gas pools.

Oil or Gas in Place

In many pools the amount of oil or gas underlying certain portions may differ substantially from the amount underlying others, so that owners of richer tracts are unwilling to agree to participation on a simple acreage basis as a fair measure of relative ownership. In such cases it is usually possible for the owners to agree to participate on the basis of the amount of oil or gas underlying each property.

Determination of the amount of oil or gas underlying each property requires measurement or estimation of the following:

1. The productive acreage.
2. The thickness of the producing formation.
3. The net productive thickness of the formation exclusive of barren zones, such as lenses of shale.
4. The porosity of the productive strata.
5. The connate water content of the productive strata.

The data available on each of these factors are usually plotted on maps covering the entire pool and are contoured or averaged, as required, in the light of the geologic nature of the reservoir and the completeness of the available information. From such maps, determination of the amount of oil or gas underlying each property becomes a straightforward procedure.

If only oil is involved, the amount underlying each property may be expressed in reservoir barrels, or the formation volume factor may be determined and the oil volume corrected to the basis of stock-tank barrels at 60°F. The latter is the usual procedure.

If only dry gas is involved, the amount underlying each property is usually corrected to a standard reference pressure and temperature, usually atmospheric pressure and 60°F.

If a gas-condensate reservoir is involved, the condensate content of the gas is determined and may be indicated separately from the remainder of the gas.

Recoverable Oil or Gas in Place

The participation basis agreed upon may be the quantity of recoverable oil or gas underlying each property instead of the total quantity. In such event, the same determinations must be made as for the total oil or gas in place, with the added step of applying percentage recovery factors.

Value of Oil and Gas

The use of acreage alone, the amount of oil or gas in place, or the amount of recoverable oil or gas in place is confined almost exclusively to unitization of a single reservoir that contains only one type of fluid, either oil or gas. Since oil and gas have different values it is not possible to make a direct comparison between a certain quantity of gas underlying one property and a certain quantity of oil underlying another. When both oil and gas are involved, or when a field consisting of multiple reservoirs that contain oil or gas of different character and different unit value is unitized, it is usually necessary to take these values into account in arriving at an acceptable basis of participation.

The value of the oil and gas underlying each property may be determined on the basis of either the total quantity of each in place or the recoverable quantity of each. The basis for assigning value may be the prevailing market price for the oil, gas, and condensate of the character and grades involved at the time a field or pool is unitized, or provisions may be made for future adjustments in accordance with future changes in price.

When both oil and gas in the same reservoir are involved, the percentage participation based on value may be on either the respective values recoverable by normal operation or the values recoverable by the improved operation expected from unit operation. If the former is employed, the amount of oil recoverable by normal operation is determined and is assigned a value based on its market price. The amount of gas recoverable by normal operation and its value are similarly calculated, with account taken of the recoverable condensate content of the gas, if any. The values of oil and gas are then totaled and the percentage of the total value represented by the oil or gas underlying each property is determined. It will be noted that when this method is employed the owners of properties underlain solely by gas share in any increased oil recovery that results from the unit operation and are thus compensated for the retention of their gas in the reservoir to assist in effecting the additional oil recovery.

SHARING OF COSTS

The participants in a unit share the costs of development and operation in proportion to their share in the production, but development and production costs incurred by the individual operators prior to unitization require special consideration. As there is no sharing of the oil and gas produced prior to unitization, operating costs already incurred are usually absorbed by the individual operators. However, certain physical facilities useful to or required for the unit operation may be acquired by the unit and their investment be shared ratably by all.

Original costs of leases are not considered. Such lease burdens as royalty, overriding royalties, payments out of oil, carried working interests, etc. are the responsibility of the working-interest participant and are paid by him out of his proceeds from the unit. Development costs reflecting investment in roads, camps, wells, and plants for water, for compression of gas, for recovery of natural gasoline or condensate, or for generation of electricity are absorbed by the unit if these facilities are required for the unit operation and are acquired by the unit. It is the customary practice for each operator to convey to the unit at either a fair replacement or a depreciated value his complete subsurface and surface investment and to receive in return a credit against his percentage of the total unit investment based on his percentage interest in the unit. In some cases a lessee may proceed to develop his property to bring his percentage development in line with that of others so that his contribution to the unit will be in line with his percentage interest.

There are some cases in which a unit will not need all of the facilities already installed individually. For example, an operator may have a camp for housing district personnel, or other items not useful to the unit. Arrangements are usually made in those cases for retention by the individual of those facilities that he requires or that are not required by or suitable for the unit. Such arrangements seldom apply to plants, and rarely to wells, unless they have no connection with the development or production of the unitized substances.

GENERAL ASPECTS OF UNIT OPERATIONS

It has been implied in the foregoing that establishment of participation in a unit is limited to the basis of acreage, to the amount of oil or gas in place, to the recoverable oil or gas in place, or to the value of oil and gas in place. There is, however, no simple rule to follow in deciding what formula is to be used for determination of the percentage participation in a unit operation.

A fair exchange of rights may be said to have been obtained when the rights to produce oil and gas from certain tracts have been traded for rights to a share in the total oil and gas produced from all of the tracts involved in the unit in such percentage as is considered fair and equitable by all participants.

Such exchanges have been based on evaluations that have included many factors, such as subsurface pressures, percentages of produced water, lifting costs, potentials of wells, maximum daily rates of production allowed under state allocation, and many others. Should any proposed factor not fit the particular case under consideration, or should its use be unacceptable, the individuals involved may be relied upon to object, and a fair basis of exchange will not be determined until a satisfactory agreement is reached among all concerned. It should be noted that there is no actual exchange of oil and gas but only an exchange of the rights to produce oil and gas so that these rights can be exercised jointly for the mutual benefit of all.

These exchanges go further than stated. They are a recognition of property rights, and they provide protection of property without the necessity for each individual to take independent action to protect his own property. It has been seen too frequently that the steps taken by the individual to exercise his right to develop and to produce oil, or the right that he exercises on behalf of his lessor, may result in the denial to his neighbor of an equivalent right. Such denial to the neighboring owner does not result from any act of ill will or that is other than necessary and accepted oil-field practice under individual operation. This denial may result from the expansion of a gas cap, from the encroachment of water, from a reduction of reservoir pressure, which may or may not create migration, but which may increase the viscosity or cause shrinkage of the reservoir oil, change interfacial tensions, cause retrograde condensation, or otherwise decrease the ultimate recovery. The same effects may adversely affect the owner in question to as great extent as or even to a greater extent than his neighbor is affected. There is no question of right or wrong, but there is a question as to whether there is not a better way to conserve our oil resources than to continue to follow the old rules and practices. This better way can be developed only if all participants are consistently fair in arriving at the proper basis for exchange of rights in each individual case.

Obstacles to Unit Operation

Unit operation is being adopted in an increasing number of fields as the owners see more clearly that it increases ultimate recovery, improves efficiency, and increases the return to both landowner and lease operator. However, there continues to be mistrust by some, caused largely by a misunderstanding of the aims of unit operation and ignorance of its accomplishments. Unfortunately, there are difficult individual cases and short-term outlooks as well as other factors that create obstacles to unit operation. Refusal to cooperate or to join in a unit program is limited neither to the small nor to the large operator. Both weigh the various factors as each reservoir or trade is being considered. Some of the factors that have obstructed the adoption of unit-operation programs are reviewed in the following:

Pride of Ownership

Pride of ownership enters into every negotiation. The reaction of the individual to the release of complete independent rights in anything he owns in exchange for a fractional participation in the whole is unpredictable. The probability of an increased return may not be sufficient to overcome this innate, though perhaps unexpressed, pride of ownership. This pride is tied closely to such feeling of the individual as the love of his land or of other property. When such feeling is strongly held, by either a working-interest owner or a royalty owner, it may prove unsurmountable.

Pride of Operational Control

Pride of operational control closely follows pride of ownership. Most operators consider themselves more efficient than others. A particular property may be the only holding of a small operator or the only substantial holding of a larger operator in the area. Relinquishment of operation might result in the disbanding of an organization. There is sometimes the desire to be engaged in work personally as opposed to release of direction to another group that must necessarily prorate the cost of such supervision. These considerations have often led to resistance against the adoption of a program of unit operation.

Lack of Reservoir Data

Exchange of property rights in the formation of a unit must rest on a common acceptance of values. An unproved geologic structure may easily be shared on an acreage basis with a sharing of the initial costs from all of the acreage and the costs after production on the proved productive or participating areas. However, once a reservoir has been proved for production additional sets of values are introduced. These values are usually based on the productivity as measured by various yardsticks. These units of measurement, however expressed, are reservoir data. The greater the amount of reservoir data available the more improved are the chances that all owners can accept a common measure of value based on the actual measured characteristics of the reservoir in question. However, the lack of adequate data has often delayed the making of an agreement. The deficiency has sometimes been remedied by joint effort in securing the data after a unit operation has been accepted in principle. In other instances the lack of such data has stopped consideration, as no common ground for agreement could be found.

Structural or Other Advantage

The basic factors that govern the migration of oil and gas are well known, and the advantages that accrue thereby to densely drilled tracts or to certain structural positions in some reservoirs are thoroughly appreciated. A structural advantage may be held by a property located up dip in a water-drive pool, down dip in a gas-cap-drive pool, or in a central location in a reservoir operated by both gas drive and water drive. Under the allocation formulas sometimes employed a small tract may benefit by migration of oil from less densely drilled surrounding tracts. In all such cases the owner of the tract having the advantage may look askance at proposals to share on an equal footing with others in a unit operation. In some instances the increased ultimate recovery to be expected from the unit operation may be more than adequate to compensate for relinquishment of a special advantage. In others, however, the owner of a favorably situated property may consider it advisable to retain his individual interest, and it may be impossible to arrive at any mutually satisfactory basis on which he can participate in a unit operation.

Profitable Obstructionism

The advantages enjoyed because of either structural position or the effects of certain allocation formulas are not held lightly by some operators. In many instances the particular advantage held by such an owner may be greatly increased if the remainder of a reservoir is treated as a unit and production practices are adopted that will increase the total ultimate recovery. Such an operation may even increase the amount of drainage accruing to an advantageously located tract. For example, a tract located near the top of a reservoir may be expected to benefit appreciably from artificial pressure maintenance brought about through injection of water.

Instances have been known where certain operators have held out for many times the value reasonably assignable to their property as they foresaw the multitudinous advantages that would accrue to them if the remainder of the reservoir were placed under a fully coordinated program to increase the recovery. In other instances operators have insisted that certain unreasonable factors be given weight in the basis of participation. In most of these cases the advantages foreseeable by an operator relate primarily to long-term profits; however, other types of obstructionism have also been encountered wherein owners have refused to participate in a unit operation but have offered their property for sale at exorbitant prices. If unit operation is to develop in the future in the constructive manner that its advantages would seem to justify, all attempts by certain individuals to take advantage of others must be firmly resisted.

Prohibitions in Leases

Landowners have in some instances insisted on a lease provision prohibiting the pooling of their acreage with other acreage or prohibiting the mixing of produced gas with gas produced from other lands. Such a provision effectively precludes injection of gas or use of a central plant in which natural gasoline may be extracted, with the residue gas returned to the properties. Although approval of the royalty owner to a unit agreement is always desirable and is often necessary, such prohibiting clauses in leases are often an obstruction to the negotiation.

Widespread Distribution of Royalty

Widespread distribution of royalty or mineral interests creates a multiplicity of problems. Such distribution generally results from the sale of very small shares of royalty to many individuals. Often there are an appreciable number of estates or trusts involved. The number of people to be interviewed, the court appearances, and the documentary costs can sometimes easily consume more time and expense than can reasonably be devoted to securing all of the necessary approvals for a unit agreement. In a sense, leases are merchantable documents and, in passing from one owner to another, may acquire not only overriding royalties but also various types of working-interest arrangements that may add to the complexity of forming a unit. Carried working interests, whether for a fixed final sum or permanent interest or payments out of net profits, are not in themselves important hindrances, as they are obligations to be met by the working interest itself. However, there are sometimes certain restrictions in subleases that must be carefully studied in order to avoid unexpected situations that might arise to the discomfiture of all.

Mistrust

Unit operation, although not new, has not been widely enough adopted for very many to be experienced in its application. As a result, it has had its share of imperfect contracts and unsatisfactory situations. Each of these has aroused criticism more appropriately directed to the individual case than to the principle of unit operation.

The only true cure for any mistrust that may have arisen in the past, and the only sure means of preventing mistrust in the future is for all agreements to be based insofar as possible on a complete and satisfactory meeting of the minds of all parties. The minority must be heard in a unit operation; it is a union of interests joined together not only for the common good but also for the good of each individual who has joined in the operation. Unanimous approval of each change in operation or each major investment is just as desirable as is the original unanimous entry into a unit. Disgruntled participants will not enter another unit and will not hesitate to express their dissatisfaction to others.

Fear of Reduced Production

Many have the notion, particularly royalty owners, that a unit operation will result in a reduced rate of production and will thereby cause a reduction of their current income. This feeling is very likely a carry-over from the period prior to state regulation, when, as pointed out in Chapter IX, cooperative development and unitization were advocated primarily as a means of reducing excessive drilling and preventing waste caused by wide-open production.

As has been explained, that situation has been changed. Drilling and production are now both regulated by the states in most important producing areas. Unit operation as now proposed has nothing to do with the control of production rate, that being ordinarily the responsibility of the state; it has as its sole objective increasing the recovery. To the extent that a unit-operation program makes possible pressure maintenance and other operations designed to increase recovery it has the effect of sustaining and extending the ability of a reservoir to produce. The result is usually a higher rate of production over a longer period than would be possible without such operation.

It is probable that the misunderstanding with regard to this question can be eliminated only through wider dissemination of information regarding the behavior of petroleum reservoirs and the requirements for increased recovery.

Legal Obstacles

In some states that have strong antitrust laws operators hestitate, and many refuse, to enter into unit-operation agreements. In order to encourage unit operation such states have found it necessary to place in their conservation laws provisions permitting or requiring unitization, or to pass separate legislation that would authorize voluntary pooling or unit operation, subject to certain prescribed restrictions.

Agreement Prior to Discovery

As appreciation of the advantages of unit operation increases it is to be expected that such operation will eventually be considered automatically as each new oil or gas field is discovered. The advantages that accrue through unit operation may be readily demonstrated and should some day become generally recognized. Furthermore, the obstacles are predictable. It would appear that elimination of or organization beforehand in such manner as to overcome these obstacles would not only decrease enormously the time and expense required for reaching an agreement, but would allow much earlier application of improved operating methods.

The simplest and easiest procedure would be to enter into an agreement prior to the drilling of exploratory wells on a suspected structure. At such a stage the basis of participation could be developed without the introduction of demands for special consideration of any real or fancied advantage. In such event, the unit area should be made sufficiently large to cover the entire possible producing area. A standard agreement with accounting procedure could be developed and used for such purpose. Unit operations would be facilitated if all lease contracts were written to allow it, or, if such were inadvisable, if they were at least so written as not to contain clauses that act as a definite bar to unit operation.

Need for Absolute Fairness

Unit operations of oil and gas pools must from the beginning and throughout be designed for and directed to the end of more efficient and more economic recovery for the benefit of the individuals who join the operation by pooling their rights to produce with the similar rights of others. This action presupposes and demands absolute fairness in the creation of the unit and throughout the operations.

The essential needs leading to unit operations are confined to the production and recovery of petroleum. They do not extend to its transportation, marketing, or refining, beyond such gathering and processing as may be required to carry on the production operations, to recover the product, and to place it in a marketable condition. No party to a unit should request or receive any preference or special consideration not fundamental to his rights as a producer of oil and gas, nor should any of his rights be denied. The right of each participant to take in kind his share of the oil, gas, condensate, natural gasoline, or liquefied petroleum gas produced by the unit should be absolute. It is essential, if unit operation is to continue to develop and to find wide support as a basis for more efficient recovery of oil and gas, that it be confined to the purpose of preventing waste and protecting the property rights of the various persons involved.

EFFECTS OF UNIT OPERATIONS

The effects of unit operations, considered broadly, should be analyzed in relation to all who have an interest in petroleum, whether direct or indirect.

Those concerned may be divided into three groups, as follows:

1. Those interested in the supply of petroleum but not directly engaged in its production or deriving income directly from its production. This group includes those engaged in transportation, refining, marketing, and distribution of oil and gas, as well as the general public.

2. Those receiving income directly from petroleum production but not participating in the costs of production. This group includes

the royalty owners, and government bodies deriving income from taxes on production.

3. Those directly engaged in the production of petroleum, who are concerned with costs as well as returns.

As has been explained in the technical discussions in prior chapters, the ultimate recovery from an oil or gas pool may be increased by certain operating practices or may be reduced by others. The specific effect of a unit operation is to make possible through cooperative action the avoidance of those production methods that cause underground loss, and the adoption of those methods that will increase recovery. It will facilitate the incorporation into future practices of those technical advances being made by the industry through research and study.

If these results be taken to be the ultimate effect of unit operations the effects on the various interested groups may be analyzed in terms of the effects of improved recovery techniques under unit operation.

Effect on Total Supply

The concern of the first group, those not deriving income directly from petroleum production, but more or less dependent on its availability, is with the total supply and the price. It seems reasonably obvious that improved recovery practices will increase both the total supply and the stability of the supply in that these methods sustain producing capacity. The long-range effect on price should be to postpone, through increase of the ultimate recovery from discovered petroleum reserves, those increased costs and probable increases in price that must inevitably come as new oil and gas reserves become more difficult to discover.

Effect on Royalty Owners and Taxing Bodies

The income to royalty owners, and revenues to taxing authorities from severance and production taxes, depend only on the amount of oil and gas produced, regardless of costs. Royalty income and tax income are maintained, stabilized, and prolonged by those operations that increase recovery. As far as the royalty owner is concerned, the effect is not only to maintain his income at a higher level for a longer period than he could expect without unit operation, but also to protect his income from the risks associated with individual operation.

The same profit incentive that leads an operator into the petroleum industry, to engage in the search for and production of petroleum, leads also to unit operation. Unless it can provide a profit, it has no appeal, for it is not good business. For the producer this profit incentive comes from three directions. To the extent that through unit operation ultimate recovery of oil is increased, the result is the same as if the exploratory and development wells had discovered a greater reserve of oil in the same property. To the extent that property rights are safeguarded over the life of an operation, values in the enterprise are stabilized and there is removed an element of risk associated with individual operation, under which adverse drainage or other effects of individual development might lead to premature depletion and abandonment of any particular property. To the extent that development and operating costs are reduced, the effect is as direct, immediate, and tangible as would be a mechanical improvement that suddenly reduced the cost of drilling.

By way of summary, the net effect on the producer is a greater total return, a higher sustained rate of return, and a protection of return. Economies are effected that may or may not reduce total costs, but that permit the necessary expenditures in other producing facilities required to obtain the expected greater return.

For example, efficient recovery requires a great deal of fundamental reservoir data. Such information is often expensive. Such producing facilities as a cycling plant, or plants for injection of water or gas to maintain reservoir pressure, often require large investments. In a unit operation the savings that may be made through elimination of unnecessary wells may provide the capital for such investments. Cycling plants and pressure maintenance plants are very effective substitutes for unnecessary wells, in that they can be used both to sustain production rates and to increase the total recovery.

The operating economies that may be effected through unit operation are important not only as items leading to cost reduction, but have an independent effect on the total recovery. As has been explained in earlier chapters, complete recovery from a petroleum reservoir is never obtained, the extraction always ceasing when the economic limit is reached. In the final analysis one process is more efficient than another merely because it permits the depletion to be carried to a more advanced stage before rising costs and dwindling income force the operation to cease. Thus, an operating economy always increases ultimate recovery, in that whatever process is employed has its life correspondingly extended.

The stabilization and maintenance of production rate that may be obtained through a unit operation contribute in other ways to profitable conservation. For example, they may make feasible the extraction of natural gasoline and the marketing of casinghead gas through the profitable investment of capital in the required facilities where a less stable and more uncertain supply of gas would not warrant its processing and might make it an unattractive supply to a purchaser.

The effects enumerated all apply to the total return or the total costs involved in an entire pool. Their net effect, in the aggregate, is to make the operation as a whole more profitable than would be the aggregate effect of individual operation of each property. The total incentive is rather clearly obvious. Whether each individual producer can see such an incentive in the light of his own circumstances is not necessarily obvious. If no particular producer has any unusual advantage through special circumstance over others in the same pool it would seem reasonable to presume that the individual advantage and the common advantage would be much the same. Under certain special circumstances the peculiar advantage held by an individual may be so great that it is difficult for him to find a personal incentive in a unit operation. However, in a whole pool the stakes are usually large, and the aggregate advantages obtainable through unit operation are often quite great. Where such a situation exists it seems reasonable to presume that the individuals involved will usually be able to develop a basis of participation that will provide sufficient incentive for each to cause him to enter a unit as a matter of sound business.

INDEX

A

Accumulation of oil and gas in reservoirs, 68
Acreage, allocation based on, 262
  basis participation in unit operation, 283
Allocation of production
  acreage basis, 262
  among fields, 251, 255
  difficulties, 258
  early approaches, 260
  New Mexico, 262
  potential basis, 260
  principles governing, 251, 256, 272
  recoverable oil basis, 256
  unit basis, 261
  well basis, 260
Allowables, transfer, 279
American Association of Petroleum Geologists, 14, 70
American Bar Association, Section of Mineral Law, 251
American Gas Association, 29, 37
American Institute of Mining and Metallurgical Engineers, Petroleum Branch, 14
American Petroleum Institute, 14, 15, 37, 195
  declaration of policy on allocation of production, 256
  Special Study Committee on Well Spacing and Allocation of Production, 209, 256, 258
Aquifer, large needed for pressure maintenance by water drive, 205
Arkoses, 61

B

Basaltic lava, 66
Bedding planes, 50
Big Lake oil field, reservoir space, 52
Bottom water, 71
Bradford field, water flooding, 47, 187
Breccias, 60
Bubble point, 89
Buoyancy, 132, 137

C

Cable tools, conditions preventing discovery of oil, 78
  early exploration, 78
Capillary pressures, 123
Casinghead gas, 32, 87
Chalk, 65
Checkerboard Limestone, 51
Clastic rocks, kinds, 57
  pores, 50
Coal, consumption, United States, 43, 44
  conversion processes, reason for interest, 41
  possibilities of synthetic gas and motor fuel, 43
Commercial and non-commercial accumulations of petroleum, 49
Competition, effect, 13
Completion of oil wells, 168
Condensate, characteristics, 106
  definition, 115
  formation, 105
  recovery processes, 177, 244
  surface recovery, 106, 110
  yield from reservoir gas, 109
Conglomerates, 60
Connate water, content in reservoir rock, 58, 59, 61
  definition, 58, 71
  distribution in reservoir, 113, 124
  importance, 85
  measuring, 76
  wetting agent, 125
Conservation (see also Regulation or Waste)
  accomplishments, 13, 45, 252
  conflicts re property rights, 248, 268, 271, 276
  cooperation, 10, 13, 276
    essential, 14, 272
  definition, 6
  erroneous concept, 1
  future, essentials, 13, 46
  growth of movement, 250
  incentive for, 6, 10, 46
  public interest, 253
  relation to future supply, 253
  regulation. See Regulation
  responsibility for, 10
  technical requirements, 10
Consumption of coal, United States, 43, 44
Consumption of natural gas, United States, 30, 31, 43, 44
Consumption of oil, United States, 26, 30, 31, 43, 44
  world, past and present, 26
Conversions of hydrocarbons, 4, 40

Cooperative development (see also Unit Operation)
  conflicts to be settled, 276
  exchange of technical information, 278
  integration of ownership, 280
  joint ownership of facilities, 280
  need for, 276
  production practices, 279
  purposes, 277
  transfer of allowables, 279
Cores, oil reservoir, 72, 75
  representative of oil-producing formation, 126
Coring, 79
Costs, development, 22, 24
  finding, 22
  operating, 22
Critical pressure, 88, 103, 115
Critical temperature, 88, 103, 115
Crude oil. See Petroleum or Oil, also Reservoir Fluids
Cycling, definition, 180
  electric models of sweep patterns, 246
  factors affecting recovery, 245
  flushing efficiency, 180, 247
  in gas cap, 268
  mechanics, 180
  reasons for, 244
  suitable formations, 247
  sweep patterns, 246
  unit operation required, 247, 270

D

Darcy's law, 124
Demand for oil, 26
  market. See Market Demand
Dew point, 89
Discovery of oil, detection from cores, 79
  early days, 77
  methods for, 79
  reserves, U. S., history, 15
Dissolved-gas drive, 120, 127
  M.E.R. under, 152
  mechanism, 127
  pressure maintenance. See Pressure Maintenance
  ultimate recovery inefficient, 130
Doherty, Henry L., 274
Dolomites, 64
Drill-stem tests, 80

E

East Texas field, migration of oil under pressure maintenance, 237
  transfer of allowables, 279
  under-saturated oil in, 93
Edge water, 71
Efficiency indexes, recovery of oil, 171
Electric log, 73, 79
Energy resources, importance oil and gas, 43
Exploration basis of petroleum industry, 1

F

Fault fractures, 51
Federal Oil Conservation Board, 250, 274
Fischer-Tropsch process, 43
Fissures in rocks, 51
Flash vaporization, gas in reservoir oil, 95
Florence oil field, reservoir space, 52
Flow, reservoir fluids, conditions affecting, 117-140
  water in reservoir, mechanism, 204
Formation volume factor, 96
  effect on oil recovery, 114
Fuels, conversions, 4
  mineral, United States, consumption, 43

G

Gabbro, 66
Gas (see also Natural Gas), definition, 85
Gas cap, 93, 115
Gas-cap drive
  definition, 121
  flushing efficiency determination, 174
  gravity drainage, 221
  process, 130
Gas drive (see also Dissolved-gas Drive), artificial, efficiency over dissolved-gas drive, 230
  artificial, for pressure maintenance, 183, 217
    in secondary recovery, 183, 190
    mechanism, 139
  horizontal, definition, 226
    economic limitations, 230
    low-pressure vs high-pressure, 227
    mechanism, 226
    processes, 226
Gas-oil ratio, effect of structure of oil pool, 218
  index to recovery by gas drive, 192
  index to recovery efficiency, 172
Gasoline, natural, 37, 86
Gas pool, definition, 80

Gas reservoirs, condensate recovery, 177, 244
  pressure maintenance. See Pressure Maintenance
  recovery processes, cycling. See Cycling
    expansion, 175
    water drive, 176
Granite, 66
Granite wash, 61
Gravity, effect on oil recovery, 122
Gravity drainage of oil with gas-cap drive, 221
Gushers, 52, 77

H

Hardwicke, R. E., 250
Hawkins pool, pressure interference in water drive, 206
Homer field, oil movement on fault planes, 51
Hydrocarbons, natural, 4
  petroleum, phase behavior, 85
  synthetic, 4

I

Igneous rocks, 66
Industry. See Petroleum Industry
Interfacial tension, definition, 99
  effect, 123
Interstate Oil Compact Commission, 14

J

Joints in rock, 51

L

Lahee, F. H., 80
Limestone, 64
Liquefied petroleum gas, 37, 86
Liquid, definition, 85

M

Market demand, definition, 12
  need for restriction of production to, 11
Maximum efficient rate of production, 151-163
  definition, 152
  M. E. R., 152
  under dissolved-gas-drive, 152
    class 1 dissolved-gas-drive pools, 153
    class 2 dissolved-gas-drive pools, 156
    class 3 dissolved-gas-drive pools, 158
  under gas-cap drive, 158
  under water drive, 161
Metamorphic rocks, 66
Methane, 37, 86, 101
  conversion to gasoline, 41
Migration of gas, effect of pressure maintenance, 244
Migration of oil, effect of pressure maintenance, 237
  problem in conservation, 8, 249, 257
Models, electric, sweep patterns for cycling, 246
Motor fuel, from natural gas, 41
  synthetic, from coal, 43

N

Natural gas (see also Gas and Reservoir Fluids), casinghead, 32, 87
  condensate recovery, 177, 244
  condensate yield, 109
  consumption, U. S., 30, 43
  conversion into liquid hydrocarbons, efficiency, 42
  dissolved in oil, 94
    differential liberation, 95
    flash vaporization, 95
  dry and wet, 87, 104
  free in reservoir, 93
  fuel value, 35
  interrelation and interconversion to oil, 40
  marketed production increased by pipe lines, 30
  production, U. S., amounts, 29
    recent history, 37
  recovery processes, cycling. See Cycling
    expansion, 175
    water drive, 176
  separation from reservoir liquids, near-critical phases, 115
  synthetic, possible from coal, 40, 43
  synthesis of liquid hydrocarbons, 41
  use in field, 39
Natural gas liquids, reserves, 37
Natural gas reserves, associated with oil, 2
  United States, distribution by type of occurrence, 33
    estimates, 33
    outlook for development and revision of inventories, 39
Natural gas resources, 29-45

O

Oil (see also Reservoir Fluids), consumption, United States, 26, 30, 43
  consumption, world, past and present, 26
  in stock tank, formation volume factor, 96
    shrinkage factor, 97
  interrelation and interconversion to gas, 40

Oil field, definition, 80

Oil lands, integration in cooperative development, 280
  ownership, 7

Oil pool, definition, 80

Oil pools. See Oil Reservoirs

Oil recovery
  artificial stimulation, 183
  capillary pressure, 123
  development of science, 118
  difference from oil production, 117
  displacement mechanisms, 120
  effect of gravity, 122
  effect of pressure maintenance, 207, 220, 227
  effect of viscosity, 99
  efficiency indexes, 171
  efficiency, basic essentials, 141
  efficient operation of reservoirs. See Oil Reservoirs
  flow governed by compressibility of oil-gas mixture, 120
  fluid saturation of rock, 123
  fundamentals, 117-140
  gravity effect, 122
  migration of oil, effect of pressure maintenance, 237
  pressure maintenance. See Pressure Maintenance
  primary, 184

processes. See Oil-recovery Processes
  relative permeabilties, 124
  reservoir pressure, 119
  stripper wells, 182
  secondary. See Secondary Recovery
  structural advantage, 238
  surface effects and multi-phase flow, 122
  technical problem, 117
  reservoir engineering, 118
  ultimate effects of well density, 163
  water influx, natural drive, 121
  wetting phenomenon, 125

Oil-recovery processes, artificial, definition, 126
  depletion vs displacement, 142
  dissolved-gas drive, basic requirements, 127
    calculating recovery, 129
    definition, 121
    efficiency, 128, 129
    mechanism, 121, 127
    vs gas-cap or water drive, 141
  gas-cap drive, basic requirements, 130
    buoyancy, 132
    definition, 121
    effect of gravity drainage, 221
    effect of pressure maintenance, 220
    efficiency, 134
    mechanism, 121, 131
    reservoir pressure decline, effect, 133
    vs dissolved-gas drive, 142
  natural, definition, 126
  water drive, basic requirements, 135
    buoyancy, 137
    effect of reservoir pressure decline, 138
    effect on migration of gas, 244
    effect on migration of oil, 237
  efficiency, 139
    mechanism, 136
    natural, definition, 122

Oil reserves, control rate of production, 2
  estimated proved, United States, 1949, 2
    world, 28
  estimated recoverable by secondary methods, 194
  equivalent in form of gas, 41
  finding and developing costs, 22
  production and discovery history, United States, 22
  proved, types of estimates, 18
  United States, annual record, 15-22
    estimates, 2, 15-22

Oil reservoirs (see also Oil Recovery, Oil-recovery Processes, Pressure Maintenance in Oil Reservoirs, Secondary Recovery), 117-174, 182-194, 196-242
  boundaries, testing for, 72
  control of recovery, basic question, 149
    basic requirements, 150
    efficiency indexes, 171
    function of wells and well spacing, 163
    maximum efficient rate of production. See Maximum Efficient Rate of Production
    standards of efficiency, 170
    well-completion methods, 168
  efficient operation, depletion vs displacement, 142
    detection of dominant drive, 144
    prediction of future dominant drive, 147

quantitative analysis, 145
reservoir as producing unit, 141
volumetric balance, 143, 201
pressure maintenance. See Pressure Maintenance
recoverable oil, 170
residual oil saturation, 171
water influx, calculation of rate, 202
Oil resources, 15-29. See Oil Reserves, Production, etc.
Oil shales, 4
Oil-water boundaries, reservoirs, 72
Oil wells, completion, methods, 168
density, effect on ultimate oil recovery, 163
functions, 163
spacing. See Well Spacing
structural location for efficient recovery, 166
Oolites, 62
Ownership of oil lands, integration in cooperative development, 280
United States, 7
Ownership of oil underground, 7

P

Panuco oil field, reservoir space, 52
Permeability, definition, 55
measurements, 55, 126
relative, 124
Petroleum (see also Reservoir Fluids), accumulation, 68; composition, 3, 86
determination of amount in reservoir, 114
production (see also Production of Oil and Gas), United States, recent history, 37
source of power, 3
Petroleum Administration for War, 18, 264
Petroleum industry, basis, 1
business enterprise, 1
costs, 22
future, 3, 5
progress, essentials, 13
raw materials, 3
Petroleum reservoirs. See Gas Reservoirs, Oil Reservoirs, and Reservoirs
Phase boundaries, reservoir fluids, 89
Phase diagrams, reservoir fluids, 87
reservoir gas, 101, 103
Pipe lines, effect on production of natural gas, 30
Pooling, definition, 280
of small tracts, 264
Pores in rocks, 50
Porosity, petroleum reservoirs, 50
Potential, oil wells, allocation based on, 260
definition, 260
Pressure connection, petroleum reservoirs, 81
Pressure maintenance in gas reservoirs, cycling. See Cycling
reasons for, 242
by water drive, 243
Pressure maintenance in oil reservoirs, by gas cap, essentials, 216
by gas injection, 183, 217, 220
by gravity segregation of dissolved gas, 218
by horizontal gas drive, basic considerations, 226
low pressure vs high pressure, 227
by natural water drive, interference between pools, 206
large aquifer needed, 205
mechanism, 198
necessary conditions, 197
quantitative determination of degree, 201
water flow, mechanism, 204
water influx, calculation of rate, 202
by water injection, 183, 206
definition, 183
East Texas field, 237
economic advantages, 210, 223, 232
effect on oil recovery, gas-cap shrinkage in water drive, 212
gas drive, with gravity drainage, 221
horizontal gas drive, 226
water drive, artificial, 210
water drive, natural, 207
index of efficiency or necessary condition, 196
limitations, 235
migration of oil, 237
water drive, injection of gas, reasons for, 215
with gravity drainage, gas-cap drive, 221
injection of gas, 225
rate of production, 225
Prices, relation to supply and demand, 2
Prices, distress, cause and effect, 12
Production of natural gas, United States, amounts, 29
recent history, 37
Production of natural gas liquids, recent history, 38
Production of oil, continuity depends on exploration, 2
flush, 182
future supply, 3

  growth due to technologic progress, 45
  limits on rate, 1
  maximum efficient rate. See Maximum Efficient Rate of Production
  need for control of rate, 10
  recent history, 37
  restriction to market demand. See Market Demand
  stripper, 182
  wide-open as cause of waste, 9, 250
  United States, annual since 1900, 15
    by states, 1950, 19
    cumulative since 1859, 15
    present rate, 15
  world, cumulative, 28
    distribution in 1949, 28
Professional societies, role, 14
Profits, required for exploration and development, 2

Q

Quartzite, 68

R

Radioactive log, 79
Recoverable oil, 170
Recovery. See Oil Recovery
Reed City pool, water encroachment, 52
Regulation
  allocation. See Allocation of Production
  authority for, 10
  conflicts re property rights, 256, 268, 271, 272, 276
  control of reservoir, 11
  deficiencies, 270
  evolution, 250, 255
  need apparent, 9, 249
  objectives and requirements, 255, 272
  protection of property rights, 251, 255
  restriction of drilling, 261
  restriction of production, 10, 250, 255
    to market demand, 11
  special problems, 257-270
    condensate reservoirs, 269
    excessive drilling, 261, 263, 265
    oil migration and structural advantage, 257
    pools with gas overlying oil, 267
    small tracts, 262
    wells, 259
  technical and administrative requirements, 10, 251, 257
  unit operation needed as supplement, 269, 272, 274
    waste-prevention statutes, 9, 251, 256
Repressuring, 191
Reserves. See Oil Reserves, Natural Gas Reserves
Reservoir engineering, definition, 118
  development, 118
Reservoir fluids, characteristics, 85-116
  determination of oil and gas in place, 113
  distribution, 112
  effect of initial reservoir conditions, 111
  gas, composition, 107
    condensate formation, 105
    condensate yield, 109
    density and expansion, 108
    determining composition, 107
    dissolved, 94
    dry and wet, 87, 104
    free, 93
    pertinent properties, 106
    phase behavior, 101
    phase diagrams, 103
    sampling, 107
    state, determining, 108
    water vapor content, 111
  gas cap, 93, 115
  mutual solubility of oil and gas, 101
  near-critical phases, 115
  oil, calculation of properties, 97
    change during production, 98
    composition, 92
    gas dissolved in, 93, 94
      liberation, 94
    pertinent properties, 91
    sampling, 91
    saturation pressure, 92
    stock tank measurements, 96
  petroleum, phase behavior, 85
    phase boundaries, 89
    phase diagrams, 87
    retrograde condensation, 102
    states of matter, 85
  separation of liquid from gas, 115
  state in reservoir, 89
  temperatures, 97
  two-phase reservoirs, 115
Reservoir pressure, 111, 119
Reservoir pressure decline, effects, in dissolved-gas drive, 128
  effects, in gas-cap drive, 133
    in water drive, 138
    on properties of reservoir oil and gas, 98-100
  index to recovery efficiency, 172
Reservoir rock (see also Reservoirs), arkoses, 61
  basaltic lava, 66
  chalk, 65
  characteristics, determining, 74
  clastic, 57

  conglomerates and breccias, 60
  granite, 66
  granite wash, 61
  igneous, 66
  limestones and dolomite, 64
  metamorphic, 66
  non-clastic sediments, 64
  oolites, 62
  quartzite, 68
  sands and sandstones, 58
  schists, 66
  serpentines, 67
  shales, 63
  silts and siltstones, 57
  space. See Reservoir Space
  storage space, 48
  tuffs, 63
Reservoir space. See also Reservoirs
  bedding planes, 50
  contents, 71
  determination of amount of, 76
  faulted rocks, 51
  fissures, 51
  joints, 51
  pores and porosity, 50
  rock. See Reservoir Rock
Reservoirs, boundaries, testing for, 72
  cap, 48
  commercial and non-commercial, 49
  contents, 71
  definition, 48
  discovery methods, 77
  earth pressures, 111, 119
  fluids. See Reservoir Fluids
  free gas in, determining, 76
  gas. See Gas Reservoirs
  multiple layers in, 81
  oil. See Oil Reservoirs
  saturation as measure of fluid content, 123
  single oil pool, recognition, 81
  space. See Reservoir Space
  storage space, 48
  study essential, 47
  temperatures, 111
  traps, 48, 70
  two-phase, 115
Residual oil saturation, 171
Retrograde condensation, 102
Rotary drilling, 78
Royalty, 7
  widespread distribution obstacle to unit operation, 290
Rule of capture, 248

S

Sampling, reservoir gas, 107
  reservoir oil, 91
Sands and sandstones, 58
Salt Creek field, water encroachment, 52
Saturation, measure of fluid content of reservoir rock, 123
Saturation pressure, 92
Schists, 66
Serpentines, 67
Secondary recovery, 182-195
  areas in which applicable, 186
  conditions detrimental, 184
  definition, 184
  development expense, 187
  gas injection (repressuring), 190
  limitations, 193
  oil economically recoverable, estimates, 194
  reference literature, 195
  selection of pools for, 184
  water flooding, discovery of use, 47
    mechanism, 139, 188
    pressure maintenance, 207, 210
    well patterns, 187
    well spacing, 186
Shales, 63
  oil, 4
Shaw, E. W., 29
Shrinkage, gas cap, 212
  factor, definition, 97
Silts and siltstones, 57
Solid, definition, 85
Stock tank, formation volume factor, 96
  shrinkage factor, 97
Stratton field, transfer of allowables, 279
Stripper stage in oil production, 182
Structural advantage, concept, 238
  obstacle to unit operation, 289
  problem in conservation, 257
Synthetic fuels, 4, 40-43
Synthetic lubricants, 4

T

Technical information, exchange, 14, 278
Traps, 48, 70
Tuffs, 63

U

Unitization, definition, 281
Unit operation (see also Cooperative Development), agreement prior to discovery, 292

aid in conservation, 259, 264, 267, 269, 270, 272
cycling of gas reservoirs, 247
definition, 281
earlier recognition of advantages, 274
effects, groups concerned, 293
on producers, 295
on loyalty owners and taxing bodies, 294
on total supply, 294
equitable in repressuring, 191
for efficient oil recovery, 242, 275
formation of unit, 281
obstacles, 287
participation bases, acreage, 283
oil or gas in place, 284
recoverable oil or gas, 284
value of oil and gas, 285
purposes, 277
reexploration needed for present conditions, 274
sharing costs, 285

U. S. Bureau of Mines, 30

U. S. Geological Survey, 15, 29

V

Viscosity, definition, 99
Volumetric balance, concept, 143
data required for, 144
uses, 143
for calculation of water influx, 201
for determination of flushing efficiency, 174
for determination of gas-cap shrinkage, 215
for prediction of reservoir behavior, 147
for quantitative analysis of reservoir behavior, 145

W

Waste of oil and gas (see also Conservation), aboveground, 9, 11, 248
casinghead gas, 32
causes, 7, 9, 248
prevention, 10
slight in dry-gas reservoirs, 269
underground, 9, 11, 265

Water drive
artificial, 139
secondary recovery, 187
completion of wells, 169
delayed, 200
determination of flushing efficiency, 174
effect of reservoir pressure decline, 138, 207, 210
efficiency of oil recovery, 139
gas cap shrinkage, 212
location of wells on structure, 166
maximum efficient rate of production, 161
mechanism, 135, 204
mechanism of oil displacement, 136
migration of gas, effect on, 244
migration of oil, effect on, 237
natural, definition, 122
pressure maintenance by. See Pressure Maintenance
quantitative analysis, 145
qualitative detection, 144
recovery of condensate by, 179
recovery of gas by, 176
requirements for, 135
structural advantage under, 238

Water encroachment, 52

Water flooding, discovery of use, 47
mechanism, 139, 187
pressure maintenance, 210
well patterns, 187, 210
well spacing, 188

Water-oil ratio, measure of recovery efficiency, 173

Well potential, definition, 260

Well spacing, function in control of production, 163
in water flooding, 188

West Edmond oil field, reservoir space, 52

Wetting, effect in oil reservoir, 125

Wilson, W. B., 70

Woodbine formation, Texas, pressure interference in water drive, 206

Z

Zwolle oil field, reservoir space, 52

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